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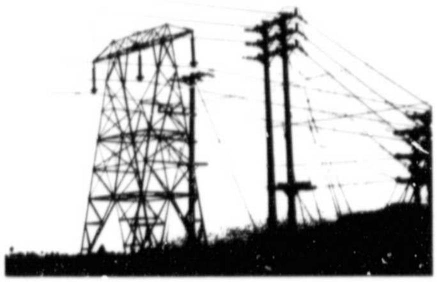
California Methanol Assessment

Volume I: Summary Report



March 1983

Prepared by
Jet Propulsion Laboratory
and
Division of Chemistry and Chemical Engineering
California Institute of Technology
Pasadena, California

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California Methanol Assessment

Volume I: Summary Report

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March 1983

Prepared for
Electric Power Research Institute
Energy Resources Conservation and Development Commission, State of California
through agreements with National Aeronautics and Space Administration,

and

Atlantic Richfield Company
Chevron USA, Inc.
Conoco Coal Development Company
E.I. du Pont de Nemours Co., Inc.
Exxon Research & Engineering Co.
Ford Motor Company
General Motors Corporation
Litton Energy Systems
Pacific Gas & Electric Company
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Southern California Edison Company
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(NASA Tasks RE-152, Amendment 297, CEC 500-82-024; RE-152, Amendment 326, EPRI TPS81-795; and Caltech Work Order 91909).

ABSTRACT

A joint effort by the Jet Propulsion Laboratory and the California Institute of Technology Division of Chemistry and Chemical Engineering has brought together sponsors from both the public and private sectors for an analysis of the prospects for methanol use as a fuel in California, primarily for the transportation and stationary application sectors. Increasing optimism in 1982 for a slower rise in oil prices and a more realistic understanding of the costs of methanol production have had a negative effect on methanol viability in the near term (before the year 2000). Methanol was determined to have some promise in the transportation sector, but is not forecasted for large-scale use until beyond the year 2000. Similarly, while alternative use of methanol can have a positive effect on air quality (reducing NO_x, SO_x and other emissions), a best case estimate is for less than 4% reduction in peak ozone by 2000 at realistic neat methanol vehicle adoption rates. Methanol is not likely to be a viable fuel in the stationary application sector because it cannot compete economically with conventional fuels except in very limited cases. On the production end, it was determined that methanol produced from natural gas will continue to dominate supply options through the year 2000, and the present and planned industry capacity is somewhat in excess of all projected needs. Nonsubsidized coal-based methanol cannot compete with conventional feedstocks using current technology, but coal-based methanol has promise in the long term (after the year 2000), providing that industry is willing to take the technical and market risks and that government agencies will help facilitate the environment for methanol.

Given that the prospects for viable major markets (stationary applications and neat fuel in passenger cars) are unlikely in the 1980s and early 1990s, the next steps for methanol are in further experimentation and research of production and utilization technologies, expanded use as an octane enhancer, and selected fleet implementation. In the view of the study, it is not advantageous at this time to establish policies within California that attempt to expand methanol use rapidly as a neat fuel for passenger cars or to induce electric utility use of methanol on a widespread basis.

ACKNOWLEDGMENTS

The original concept for the California Methanol Assessment was developed by Professor William H. Corcoran of Caltech and James Kelley of JPL. They established a relationship among public and private organizations with diverse interests in methanol, thereby enabling the initiation of the California Methanol Assessment. Professor Corcoran was the Principal Investigator for the Assessment until his unexpected death in August 1982. Caltech Professor George Gavalas assumed the role of Principal Investigator and Caltech/JPL Assessment Coordinator. Professor Harry Gray, Chairman of Chemistry and Chemical Engineering at Caltech, provided information and support to Professor Gavalas and the Caltech Assessment Team participants.

A key element of the California Methanol Assessment was the interaction between the Assessment Team and representatives of public and private organizations with diverse methanol interests. The following organizations and individuals comprised the Technical Advisory Group, providing information, advice, and criticism to the Caltech/JPL Assessment Team participants.

Atlantic Richfield Company: Thomas J. Clough, John Siemssen
California State Energy Resources Conservation and Development Commission: Charles Y. Mizutani, Wendy Reid, David Maul, Ken D. Smith
Chevron USA, Inc.: John Leutwyler, Will Danker
Conoco Coal Development Company: Robert G. Jackson, Carla Stone
E.I. du Pont de Nemours and Company, Inc.: John Hannon, Don Moore
Electric Power Research Institute: Seymour Alpert, H. H. Gilman
Exxon Research and Engineering Company: Kariston Moritz, Leonard Bernstein, Terry Kett, Hugh Shannon
Ford Motor Company: Roberta Nichols
General Motors Corporation: Joe Colucci
Litton Energy Systems: Al Baxley
Pacific Gas and Electric Company: David Hovarongkura; Jim Kimball
Phillips Petroleum Company: Donn B. Wimmer
Solar Energy Research Institute: Joe Finegold
Southern California Edision Company: Charles McCarthy, George Clark
Sun Company: Walt Douthit, Dave Barmby
Texaco, Inc.: Carl Cottle, Fred Wilson, Kathy George
United States Synthetic Fuels Corp.: Larry Ruff, Jim Harlan

The California Methanol Assessment was led by Richard P. O'Toole of JPL. The principal JPL authors of the Assessment and the sections of the Technical Report they were responsible for are:

Elisabeth Dutzi: Chapters 3 and 10
Robert Gershman: Chapters 2 and 9
Ronald He[illegible]: Chapters 7 and 8
David Ma[illegible]: Chapter 5
Richard O'Toole: Chapter 4 and Summary Report
William Kalema, Caltech: Chapter 6

Supporting JPL Team members included:

Cindy Carlson
Karl Eckman
Joe Ferrall
Jack Harris
Frank Hoehn
Sue Jones
John McCarthy
Lowell Orren
Gerald Voecks
Eugene Warren
Michael Ziman

Also, Dr. Donald Rapp of JPL made a significant contribution to the study by synthesizing and incorporating many of the sponsor comments into the Technical Report from the March Technical Advisory Group meeting. In addition, Gregory McRae and Puvin Pichaichanarong of Caltech provided significant assistance in determining the probable air-quality consequences of methanol utilization.

Alice Dennison of Caltech coordinated the managerial and financial aspects of this joint JPL/Caltech activity. Pamela Hillman of the Caltech Industrial Associates Office assisted in coordinating the initial Technical Advisory Group meeting. Arlene Calvert of JPL was responsible for word processing and assembling the final report. She was assisted by Fran Mulvehill, and Susan Elrod of JPL who prepared graphical materials for the Technical Advisory Group meetings and the final report. Joyce Whitney served as Project Staff Assistant to J. Kelley of JPL and W. Corcoran of Caltech and coordinated the Technical Advisory Group meetings.

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EXECUTIVE SUMMARY

BACKGROUND

The California Methanol Assessment was organized by the Jet Propulsion Laboratory (JPL) of the California Institute of Technology (Caltech) through an interagency agreement with the National Aeronautics and Space Administration. The 18-month study was a joint effort of JPL and the Caltech Division of Chemistry and Chemical Engineering and was sponsored by various private companies and public agencies that are potential stakeholders in methanol use, production, and distribution. An in-depth analysis was performed of the status and prospects for methanol use as a fuel in California, primarily in the transportation and utility sectors. Technical data were synthesized from ongoing JPL studies, the sponsors, and other sources. The data were then analyzed for California markets to determine the role that methanol can play, the gaps in the current state of knowledge, and the efforts that are warranted to ensure an efficient and appropriate transition into the marketplace.

Methanol has long been used as a chemical and chemical feedstock. The United States currently produces about 3 million tons/year with an energy equivalent of 100 trillion British thermal units (10^{14} Btu). Methanol has many potential benefits as a fuel. On an overall basis, it has been argued that it could be the lowest cost synthetic liquid fuel. The technology exists to produce methanol from the country's extensive coal reserves as well as from peat, petroleum, coke, natural gas, and bioenergy feedstocks. In automotive and some other applications, the performance of methanol is superior per Btu to that of gasoline and other conventional fuels. Widespread methanol use could have a net positive effect on the environment because it is a clean-burning, low-polluting fuel that ostensibly yields lower atmospheric contributions of NO_x and unburned hydrocarbons. Gasoline-fueled vehicles could be built and stationary power plants could be readily adapted to use of methanol. Methanol can be produced from a variety of domestically available feedstocks and used in a variety of applications. In addition, it is noncarcinogenic.

Expanded production of methanol, unlike other synfuels, will require dedicated storage facilities and delivery systems. Thus, because it is not now in general use as a fuel, more extensive methanol use would require either new dedicated delivery systems or conversion of current systems. On a volume basis, methanol has half the energy content of gasoline, so both storage and vehicular tanks would probably need to be increased in size, with some mitigation because of better fuel performance. Although safety and toxicity problems seem to be no greater than those for gasoline, they are different from today's fuels, and their solutions would require additional education and training. Methanol is hydroscopic, but a small fraction of water can be tolerated in its use as a fuel. Also, methanol could be transported in existing pipelines if some adjustments were made for the fuel's greater miscibility, and if batched load delivery systems were set up.

For methanol to become a viable transportation fuel in the long term, both the fuel and automobile industries must participate in a strategy

involving risk on investments that will not be returned quickly. The issue of scale is important, for it has been suggested that:

(1) Methanol must ultimately be made from coal in large (25,000 tons/day or larger) western minemouth plants.

(2) Methanol must be pipelined to end-use markets in high-volume pipelines (50,000 tons/day).

(3) Automobile manufacturers must mass-produce (at least 30,000 vehicles per year at a given company) optimized methanol-fueled vehicles to achieve end-use economies of scale.

(4) Potential private passenger car buyers must see an established fuel distribution network before they will purchase neat methanol-fueled vehicles.

Each of the above points has been evaluated for the California Methanol Assessment to determine if it is a critical element in the viability of methanol as a fuel in California. Once this basic characterization of the methanol fuel system was made, the analysis focused on what could be done as the next step to facilitate an efficient evolution into the marketplace.

The State of California was chosen as a focus for the study because methanol has many potential uses as a fuel for stationary and transportation applications in California. There are unique benefits that could be derived from widespread use of methanol in California because of the State's air-quality problems and its number of potential feedstock sources for methanol. Relative to the use of conventional fuels, use of methanol could reduce the emissions of sulfur dioxide, nitrogen oxide, and reactive hydrocarbons into the atmosphere of California urban centers.

During the past several years, there has been an increase in the number of test programs for vehicles using methanol and methanol/gasoline blends. The State of California has begun fleet tests, and in 1980 the California Energy Commission (CEC) issued a policy resolution on alcohol fuels. Also, utilities and policy-makers in California have shown an interest in methanol's role in the utility sector, where it could have environmental and fuel diversification benefits.

Clearly, methanol has the potential for much greater use as an alternative fuel in California. Caltech and JPL were greatly interested in examining the realities of that potential, and together they were equipped to provide a useful interdisciplinary study of the problems and potentials. JPL's long-term commitment to the national energy program, coupled with the Laboratory's 30-year history as a leader in fuels research for space and other applications, provided unique experience with chemical processes, combustion, engines, turbines, fuel cells, environmental control, safety, toxicity, systems analysis, and policy analysis. Current methanol-based fuel cell research at JPL and emissions characterization studies at Caltech provided a rich data base. Related efforts, such as the Advanced Coal Extraction Systems study, and detailed cost models being developed for photovoltaic and other new

energy systems, ensured a background and structure conducive to a well-rounded overview of the problem.

The emphasis of the California Methanol Assessment has not been placed on generating new basic data, but rather on resolving conflicting information, performing a more detailed market analysis in California submarkets than has been published to date, and synthesizing this information into a California strategy. Some of the questions that needed to be addressed were:

(1) Could methanol become a significant fuel for California (and elsewhere) beginning in the 1980s and 1990s?

(2) When compared to alternatives, which options for the use of methanol should be encouraged for California?

(3) What are the attributes of methanol in terms of cost, value, environmental impacts, supply reliability, safety, and health?

(4) What are the possible and probable sources of supply and modes of transportation and distribution?

(5) What are viable near-term approaches for the use of methanol as a fuel in California?

APPROACH

The goals of this research effort have been to:

(1) Synthesize, evaluate, and document key technical issues (e.g., neat methanol engine efficiency, economies of scale in methanol production, environmental effects of methanol use, etc.).

(2) Identify the essential features of a mature methanol fuel industry if it should develop.

(3) Identify and characterize potential near-term and long-term methanol fuel markets.

(4) Characterize the next steps in terms of research or studies that would further refine the potential role for methanol.

(5) Determine if selected policy alternatives can significantly alter methanol potential.

After evaluating these key issues, a determination was made of the next steps to be taken in the methanol market. These steps were then evaluated from the perspective of each of the key participants (producers, users, equipment manufacturers, distributors, regulators, legislators, etc.).

Thus, the end result of this study has been to determine if there are useful transition-period strategies, policies, research activities, regulatory changes, or avenues of cooperation among the participants in the methanol

market that would facilite methanol achieving its longer-term role more efficiently. This is a very difficult problem and challenges fuel producers and distributors, automobile manufacturers, end users, government agencies, and researchers to determine sensible processes and policies within a timeframe that will allow methanol to be efficiently available for future demands.

The choice was made of the specific time periods used for near-term (1982 through 1987), transition-period (1988 to 1997), and long-term (1997 and beyond) market analyses because of constraints on the evolution of methanol as a fuel, i.e.:

(1) The near-term period of 5 years is short enough so that changes in methanol production capacity can be estimated with reasonable accuracy (plants are already in planning or construction stages) and the state-of-utilization technology is relatively fixed.

(2) The transition period from 1988 to 1997 is the timeframe in which methanol use would have to expand rapidly if it were to make a significant impact on fuel markets by the turn of the century.

(3) The long-term market is simply defined as beyond 1997 because that is a period by which some results would have to be realized to motivate action now in planning, technology development, and policy implementation.

An effort of this study has been made to examine the possible transition paths of methanol into long-term fuel and stationary source markets. Therefore, this study looks more deeply than other recent studies at the submarkets in transportation, utilities, and industry that could be important in building the supply, production, and delivery infrastructure necessary for widespread use of methanol. For example, in the transportation fuel market potential demand for methanol as an octane enhancer in Califonia is examined as a complex market in itself. The perspective of large refiners and the independents in terms of the value each would place on methanol for octane enhancement is quite different. Similarly, in the case of utilities, an attempt has been made to carefully differentiate the value of methanol in various types of generating units and under a number of environmental conditions and regulations. The results, when aggregated across the market sectors, provide the framework for identifying opportunities for structuring a transition strategy. It is not suggested, however, that this study substitutes for the project-specific analysis a company would have to do to commit to a methanol venture. The level of detail necessary for such an evaluation is simply beyond the scope of this study.

The study has also taken a fairly detailed look at the methanol production industry in the near term (1982 to 1987), as this period may also be crucial to a transition strategy. This period is significant because methanol production is already in a period of transition. The deregulation of natural gas that is now in progress will greatly alter the structure of methanol supply in the long term and may lead to significant price changes in the near term.

Individuals that contributed to this study represented a broad spectrum of disciplines, including chemical engineering, economics, petroleum engineering, policy analysis, and thermodynamics. The sponsors of the study also provided substantial data in the following areas:

(1) Production: Atlantic Richfield Co., Chevron USA, Inc., Conoco Coal Development Co., Exxon Research & Development Co., Phillips Petroleum Co., Sun Co., and Texaco, Inc.

(2) Chemical: du Pont de Nemours and Co.

(3) Utility: Electric Power Research Institute, Pacific Gas and Electric Co., Southern California Edison Co.

(4) Automotive technnology: Ford Motor Co., General Motors Corp.

(5) National synfuel incentives: Synthetic Fuels Corp. (SFC).

(6) State roles: California Energy Commission (CEC).

(7) Production equipment: Litton Energy Systems.

The findings were synthesized into an assessment framework and reviewed by JPL and by the Technical Advisory Group, which is composed of representatives of the sponsors. A key feature of the assessment approach was that the information was exchanged and discussed by the Technical Advisory Group in the same meetings that were held to review drafts of the interim and final reports. Although agreement was not reached on all points, these meetings provided an opportunity to discuss specific issues from the perspective of companies that are or might be potentially involved in methanol production, distribution, and use. Thus, although the study does not represent a consensus position of the sponsors (the conclusions are solely those of JPL), there was a free exchange of ideas so that a wide range of positions could be considered. The reader is referred to Appendix B in Volume II: Technical Report for the positions of the various sponsors on the findings.

FINDINGS

Competitive Environment

A review was made of studies of the present and projected competitive environment for methanol in Califonia with emphasis on: (1) the availabililty and price of natural gas and residual oil to California utilities, and (2) the likely range of cost for motor fuels in California. Table 1 projects the likely (base case) fuel consumption and cost for California for the utility and transportation sectors. The precise values of the forecast prices and quantities are not as important as the general climate for synthetic fuels in the transition period of 1982 through 2000. The key factors during this period are:

(1) The United States and California will remain dependent upon imported oil, although recent off-shore oil discoveries will improve California's position.

Table 1. Base Case Fuel Forecast Summary for California (quad/year)

	1980	1985	1990	1995	2000
VEHICLES					
Gasoline	1.44	1.23	1.10	1.08	1.05
Distillate	0.25	0.30	0.35	0.37	0.40
SUBTOTAL	1.69	1.53	1.45	1.47	1.45
ELECTRIC UTILITIES					
Natural Gas	0.52	0.59	0.54	0.49	0.45
Oil	0.48	0.36	0.49	0.37	0.13
SUBTOTAL	1.00	0.95	1.03	0.86	0.58
INDUSTRY					
Natural Gas	0.54	0.36	0.39	0.39	0.37
Distillate Oil	0.05	0.05	0.04	0.04	0.03
Residual Oil	0.04	0.04	0.03	0.03	0.03
SUBTOTAL	0.63	0.45	0.46	0.46	0.43
PRICES (1981 \$/10^6 Btu)					
Gasoline	10.66	9.85	12.42	14.39	15.97
Residual Oil (0.5% sulfur)	5.47	5.49	6.68	7.58	8.18
Distillate Oil	6.30	6.12	7.89	9.37	10.60
Natural Gas: Utilities	3.84	5.01	6.37	7.44	8.06
Natural Gas: Industrial	3.97	5.07	6.41	7.47	8.09

(2) Natural gas after deregulation will tend toward parity with the price of residual oil.

(3) The contribution of synthetic fuels nationally will probably be less than 500,000 barrels (bbl)/day by the year 2000.

(4) Although there is significant oil worldwide and unused capacity in OPEC to supply anticipated demands in the next 20 years at real escalation rates of 2% annually or less, political disruptions could drive prices up much faster.

(5) There is a plausible wide range of oil price scenarios in the 1990s, which work against those large-scale capital projects that must rely on high-price scenarios for viability.

(6) The real price decrease, since the peak 1981 oil price level, has severely impacted the enthusiasm for synthetic fuels and will probably negatively impact such projects even if another sudden price rise occurs.

Air Quality

A special effort of the study that coincided with ongoing research at Caltech was to perform a screening analysis of the likely impact of methanol fuel on the air quality of the South Coast Air Basin. The Basin includes the areas within the counties of Los Angeles, Orange, Riverside, and San Bernardino, which has a population of about 11 million people. The Basin has persistent and severe problems of air pollution caused by a combination of factors. There has been an extensive gathering of emissions and meterological data for this Basin, which enabled the application of analytical models.

For this analysis, an existing Caltech air-quality model was further adapted to treat methanol as a specific pollutant. The methanol chemistry was included in the model for completeness to determine how methanol would contribute to the formation of ozone. Thus, the model was able to distinguish seven classes of reactive organic compounds: alkanes, ethylene, other olefins, formaldehyde, other aldehydes, aromatics, and methanol. The various reactive hydrocarbons have different rates of reaction with NO_x and with the oxygenated species that promote the formation of photochemical smog. The model uses a Langrangian form for representation of the equations of motion that describe the diffusion and convection of chemical species within the modeling region. It calculates the concentrations of chemical species along a given trajectory of an air parcel traversing the Basin.

All calculations were based on the projected emissions inventory of pollutants for the year 2000. The air-quality impacts of methanol use are quite sensitive to this initial baseline, thus the findings discussed below should not be attributed to the intervening years between now and the year 2000. At that future date, the potential benefits of existing pollution-abatement regulations would have been realized. At the same time, it is a feasible date by which, if methanol were to become an important fuel in California, air-quality effects from this change would be felt. Calculations were performed to indicate the likely effect on air quality of using methanol as a substitute for gasoline; no estimates were made of the effects of use of methanol for stationary applications or diesel vehicles because other study findings indicated these uses to be relatively small contributors to the emissions baseline.

Some of the following conclusions apply to the complete substitution of methanol for gasoline in the South Coast Air Basin, based on projected emissions for the year 2000. Even though this is not a feasible scenario for methanol use, the intent was to bound the air-quality implications of substituting methanol for gasoline and to calculate a limiting case. Therefore:

- Even with an optimistic rate of neat methanol vehicle adoption, the maximum impact by the year 2000 would be only a 3% to 4% reduction in the peak hourly-average concentration of ozone.

- In the long term (beyond the year 2000), even the complete substitution of methanol-fueled vehicles for gasoline-fueled vehicles could lead to a reduction of 14% to 20% in the peak hourly-average concentration of ozone.

- Peak ozone concentration decreases approximately linearly with methanol substitution, starting with the year 2000 emissions inventory.

- The photochemical reactivity of methanol is relatively low.

- With use of methanol, peak ozone concentration is reduced as emissions of NO_x are reduced. The ozone concentration, however, is much less sensitive to emissions of NO_x than to reactive organic emissions.

- With methanol substitution, the ambient concentration of formaldehyde would not increase significantly.

- Total suspended particulates in general would not be greatly affected by methanol substitution; however, fine non-volatile carbonaceous particulates would be reduced slightly if methanol were substituted for gasoline. Methanol substitution for diesel fuel would make this reduction much larger.

While the assessment of effects of methanol on air quality is only an initial investigation and while the accuracy of the data used in the modeling calculations could possibly be improved, the study results clearly indicate that the impact of methanol of the South Coast Air Basin would be beneficial in the long term. For some pollutants, the potential improvements are significant. The most significant impact would be to reduce the peak level of ozone, but only if a major portion of vehicles in use were methanol-fueled. Even a small reduction in peak level would cause a reduction in the number of days that the smog episodes occur, and thereby would cause an improvement in the air quality for the residents of the Basin. Obviously, the use of methanol is no panacea for the problems of air pollution. Other pollution-abatement measures would still be needed. If neat methanol-fueled passenger cars were to become over-the-road competitive with gasoline vehicles in 1990, and from that point achieve a rate of sales consistent with the rate of adoption for deisel-fueled vehicles since 1978, the vehicle stock would be about 12% neat methanol-fueled vehicles by the year 2000. With this percentage of methanol-fueled vehicles on the road, the peak ozone would be reduced about 3.7% from the base case. Obviously, the adoption of methanol vehicles could occur more quickly, but this is unlikely given that neat methanol will not be over-the-road competi- tive for some time. Neat methanol has more barriers to overcome than diesel, so its rate of adoption will tend to be less, if anything, than the diesel experience since 1978. Therefore, the 3.7% impact on ozone by the year 2000 for neat methanol-fueled vehicles is probably optimistic and, in any case, only a modest factor in that timeframe.

PROJECTIONS

One of the goals of the study was to characterize the projected value of methanol in the private marketplace. Such a determination will reveal whether there are potentially viable markets for methanol in the near to mid term that might help transition to widespread use of methanol as a transportation fuel.

Near Term (1982 through 1987)

The methanol supply industry is already in a transition period. Adding to the progressing deregulation of natural gas and a worldwide oversupply of methanol, there is a prospect for coal-based methanol plants supported by SFC. Also, there is much uncertainty surrounding the near-term structure of the industry.

Factors acting upon the methanol industry in the near term will be:

(1) By 1985, natural gas will be deregulated and will move toward parity with the mid to low sulfur (approximately 0.5%) residual oil price. In the study's baseline scenario, this is expected to be in the \$4.75 to \$5.00 per 1 millon (10^6) Btu range in 1987 (1981 \$).

(2) Contracts for inexpensive natural gas, currently supplying the conventional feedstock for methanol in the United States, will virtually all have expired by 1985 to 1986. As a result, domestic producers will be paying deregulated market prices for feedstock natural gas.

(3) There will be excess capacity in methanol production to supply traditional chemical markets. Even if demands in traditional uses such as formaldehyde return to pre-recession levels (if the housing industry expands), the 1985 excess supply capacity will probably exceed 1 billion (10^9) gal/year in free-world markets unless fuel uses expand.

Production

Given the above factors that are operating within the industry, three possible marginal commercial production sources by 1987 are: (1) methanol from conventional natural-gas plants with unregulated gas feedstock cost, (2) new remote natural-gas-based plants, or (3) SFC-supported coal-to-methanol plants.

Virtually all of the existing plants will be operating on deregulated natural gas by 1987. Assuming a \$5.50/10^6 Btu feedstock cost for natural gas in fully amortized plants, the plant gate market price for methanol is estimated at a minimum of \$0.76/gal for methanol in 1987 (in 1981 \$). It is expected that these plants will remain viable at least through 1990, but that no new conventional plants will be built based on pipeline natural gas.

The concept of barge-mounted plants producing 2000 to 3000 tons/day from remote natural gas may become viable in this period. The key assumption here is that the remote natural gas used would be available at far-below-market gas prices. Two plant locations were evaluated for feedstock and transport costs appropriate for methanol: Cook Inlet (Alaska) and Indonesia. The implications of these cost projections are that barge-mounted plants could yield a 20% after-tax nominal return with a minimum acceptable delivered price of \$0.58 to \$0.66/gal (in 1981 \$).

Coal-based methanol plants supported by price or loan guarantees have been proposed to SFC. The study modeled a western-sited coal-to-methanol plant and unit train transportation to the West Coast. It was found to require a price of $0.82/gal delivered to California, even with loan guarantees. Thus, even with SFC support, western coal-to-methanol production will not be competitive with the other options, and it seems likely that any coal-to-methanol plants started in the 1980s will have to be subsidized with price supports. Further, subsidized methanol might tend to displace domestic production in the chemical sector, rather than in the fuels market as intended.

Use

Although methanol can be used in utilities and in industry as a boiler or peaking fuel, it must compete with conventional fuels. In the 1987 timeframe, residual oil and natural gas are expected to cost approximately $\$5.50/10^6$ Btu, and methanol should cost approximately $\$9.00/10^6$ Btu. Thus, the only potential for methanol use in the utility/industry sector would be where environmental constraints force a willingness to pay a significant premium ($\$3.00$ to $\$4.00/10^6$ Btu) for methanol. One utility application that seems to have some promise to justify premiums in this range is overfiring boilers using 10% methanol with natural gas or residual oil. Full-scale boiler tests must be done to confirm if such premiums can be justified in selected power plants where capacity is restricted because of emissions limitations.

As in utility and industry applications, there are significant near-term barriers to the expansion of refining and blending submarkets on the West Coast because of lack of availablility of other necessary blending agents such as isobutylene for methyl tertiary butyl ether (MTBE) and tertiary butyl alcohol (TBA) for low-level blends. It is expected that methanol demand for blending and refining will be only 300 to 500 tons/day in the near term because of these constraints.

There now exists a very small methanol market for commercial fleet vehicles, supported by several small companies performing vehicle conversions to neat methanol. Even if factory-optimized methanol vehicles were available and the price of methanol fuel was such that these vehicles would have an over-the-road cost competitiveness with gasoline, the near-term potential market is probably still limited to 4000 to 10,000 vehicle sales per year in California. This is due to constraining factors such as uncertainty of resale value, ready availability of methanol fuel, and required maximum trip lengths for the vehicles. If methanol vehicles were in fact sold at this volume, it would imply an increase in methanol demand of between about 20 and 75 tons/day. Such a volume is quite small in comparison to a remote natural-gas methanol plant size of 2000 to 3000 tons/day.

As shown in Figure 1, the most likely outcome in the near term is for very limited quantities of methanol being consumed within the state. The maximum competitive market size would be approximately 4000 tons/day, even if all the low-level blend potential of California were exploited. A more likely outcome is that demand will be approximately 1000 tons/day, with perhaps 800 tons/day to blending markets, 100 tons/day to vehicle fleets, and 100 to

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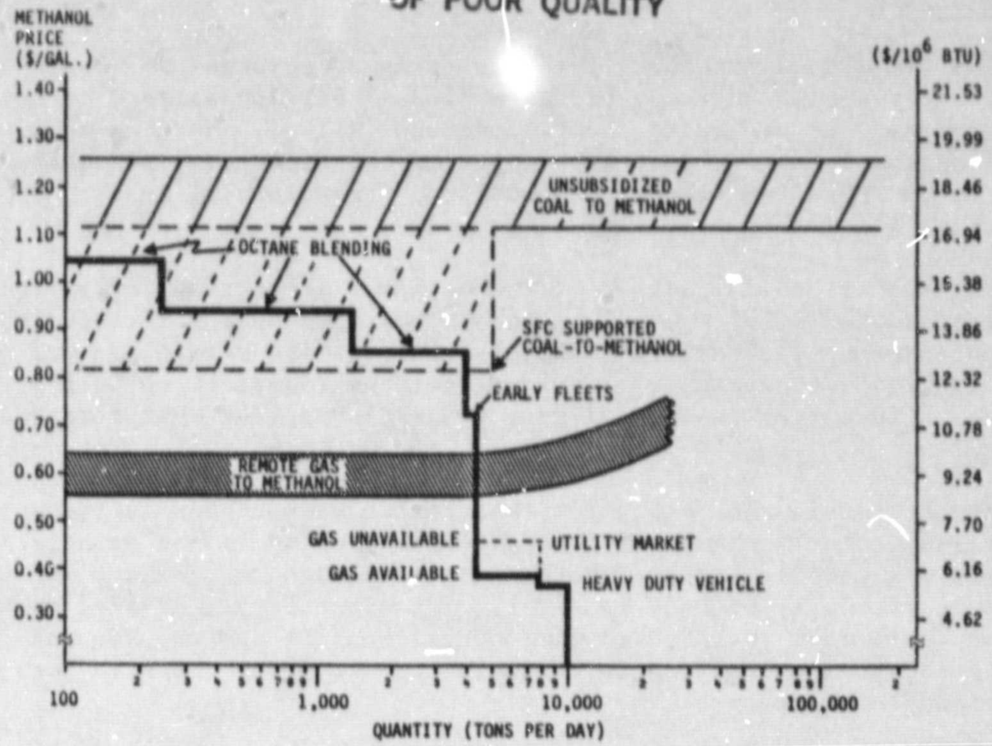

Figure 1. Projected 1987 California Methanol Market (1981 $)

200 tons/day utilized for utility experimentation. The only way that this outcome could be significantly affected would be for: (1) the West Coast TBA capacity to be expanded, (2) the regulatory climate in California to be eased to facilitate the blending with a higher allowed Reid Vapor Pressure, or (3) utility overfiring to be expanded if the potential gains are proven in large-scale tests.

Transition Period (1987 to 1997)

A characterization has been made of the effects of letting the marketplace determine methanol introduction and evolution for the timeframe of 1987 to 1997. The transition period is the most interesting aspect of the evolution of the methanol market because it is a timeframe in which production methods and sources will change, end-use technology will improve, and the fuel market in which it competes may also experience significant changes. The 10-year period from 1987 to 1997 is defined for the purposes of this study as the transition period in which major changes must occur if methanol is to be a significant fuel by the year 2000. Obviously the planning, testing, experimentation, and policy changes might begin sooner, but the impact of these activities on the market will be felt in the 1987 to 1997 timeframe.

Production

There are already capacity additions planned through 1987 based on natural-gas feedstocks that may add as much as 1 billion gallons of excess capacity relative to projected chemical demands. Thus, there is an ample supply of methanol for early utility experiments, fleet use, and octane blending in the next few years. Beyond 1987, the potential exists for additional capacity.

After a detailed comparison of the methanol production costs from both California feedstocks (bioenergy, petroleum coke, heavy oil in rock) and other out-of-state resources (western coal, Alaskan coal and remote natural gas), it has been concluded that only two options would be important to California's transition period: remote natural gas, and SFC-supported coal-to-methanol plants.

A key factor in the conclusion that remote natural gas is the most important source for methanol in the transition period is the expectation that the markets will evolve slowly. Methanol from remote natural gas is not likely to be extremely elastic in supply. At large levels of fuel demand, production costs from this source would begin to rise for two reasons: longer transport distances to California, and higher collection costs in less-developed remote sites.

The major findings in the production cost analysis are that:

(1) Methanol is most efficiently produced from remote natural gas in the transition period.

(2) Production costs from remote natural gas vary from the reference case of \$0.53/gal in 1992 up to \$0.66/gal at a 25% return and down to \$0.42/gal at a 15% return.

(3) The quantities of remote natural gas available on the Pacific Rim at \$1.50/10^6 Btu or less seem sufficient to support California's near- to mid-term fuel demands.

(4) Rapid expansion of methanol supply from remote gas resources will induce price increases as longer transport and higher collection costs are incurred.

(5) California resources are not critical to a methanol fuel transition.

(6) Methanol does seem to be in the competitive range with shale oil or to be significantly cheaper than methanol-to-gasoline or Fischer-Tropsch liquids.

(7) A high oil price scenario may also tend to induce methanol production cost increases, which offset some of the apparent gains in viability.

(8) There does not appear to be a case in which unsubsidized coal-to-methanol plants become commercial before the year 2000.

Use

Given the starting point illustrated previously in Figure 1 for the bounds on the California fuel market for methanol in 1987, similar snapshots of utility, industrial, blends and neat transport fuel markets are made for 1992 (Figure 2). During the transition period, the most important factor in the status of the methanol fuel market in California will be the competitive environment in which it must compete. The pertinent submarkets are blends, fleets, private passenger cars, industrial fuels, and utility fuels. All of these market potentials are shown in Figure 2 in terms of both breakeven prices and market sizes. Some significant changes from Figure 1 are evident, especially in the scale of the potential stationary applications market and the addition of a light-duty vehicle submarket.

As shown in Figure 2, the transportation markets are the submarkets where methanol can have a limited impact in the transition period. Low-level blends (4.5%) of methanol and a co-solvent with gasoline should be competitive at some level by 1992. The maximum methanol use would be about 3000 tons/day in California for this purpose, but actual use given TBA limitations will

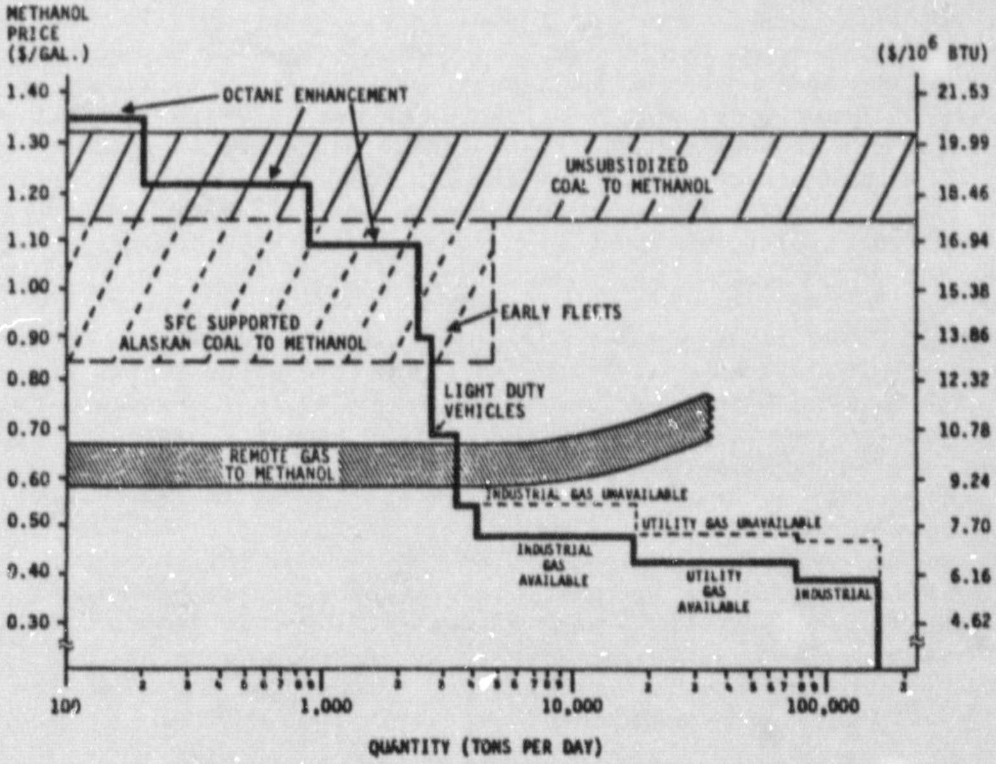

Figure 2. California Methanol Market in 1992 (1981 $)

probably be smaller, about 900 to 1000 tons/day. The fleet market is the next increment in methanol demand that would be competitive at prices up to about \$0.90/gal, but would imply a maximum methanol demand of 1200 tons/day and a more likely demand of approximately 100 tons/day.

The passenger car market would also achieve parity in the early 1990s with the over-the-road costs of gasoline, although the margin would be slight. A key factor in this analysis is that only remote natural-gas feedstocks yield methanol prices in the competitive range of fleets and passenger car markets. Because this feedstock source is not highly elastic, a very rapid penetration rate for methanol-fueled vehicles would lead to methanol production-cost increases. At rates of penetration consistent with diesel vehicles in the period of 1978 to 1982, remote natural gas is sufficient to supply both fleets and passenger cars through the 1987 to 1997 period.

Rapidly rising oil prices consistent with the high oil price scenario may improve methanol viability somewhat, but there will also be feedbacks in methanol production costs that offset part of the apparent gain in competitiveness. As a result, with either the base case or high-price scenario, methanol from coal does not seem viable through the transition period. In the low oil price scenario, light-duty vehicles do not become over-the-road competitive until beyond the year 2000, even for methanol from remote natural gas. For this optimistic case scenario, the only viable methanol market is in blending for octane enhancement or possibly overfiring in highly selective utility applications.

The potential for methanol as a fuel in stationary applications is very limited in the transition period because it cannot be produced competitively with pipeline gas or even liquefied natural gas (LNG). This situation is actually strengthened under a high oil-price scenario, where feedback effects in methanol production costs will offset likely increases in pipeline gas. Under the assumption that natural gas remains available to utilities (which seems likely), the margin for error between costs for natural gas and methanol is estimated to be sufficiently wide that methanol cannot compete on strictly an energy basis.

The only other rationale for using methanol for stationary applications in this timeframe would be that it has environmental value beyond its energy content. The problem with environmental premiums is that there are current programs in place that rely primarily on nuclear capacity, out-of-state coal generation, and renewables to achieve environmental compliance. Burning methanol within the South Coast Air Basin is neither as cost-effective as these options nor as environmentally benign with respect to NO_x and sulfur output in the Basin. The one exception to the lack of environmental premiums is the case where plants are operating well below capacity because of NO_x output limitations. These few plants are really the only transition-period methanol market in the utility sector. If bench-scale tests are verified in large-scale tests, the value of methanol may exceed that of oil or gas by more than \$3.00/10^6 Btu, which would make it a viable application.

Long Term (1997 and beyond)

Production

In the period beyond 1997, if the preconditions on methanol development have been successfully achieved, there are really only two potential feedstock sources for methanol: western coal and Alaskan North Slope natural gas. Both of these feedstocks exist in sufficient quantities to supply an established and growing methanol fuel demand, and have further strategic value as domestic sources which are not subject to Middle Eastern political and social instability. For natural gas the supply elasticity is such that quantities of 10,000 to 20,000 tons/day can probably be supplied before large supply cost increases take place. These cost increases result from increasingly higher feedstock acquisition and collection costs, and also from costs associated with longer product transport times. As a result, these costs would increase until the potential for North Slope gas could be exploited (about 10,000 tons/day). Of course, if the gas pipeline to the North Slope is constructed, methanol will cease to be a relevant option. For coal-to-methanol plants, larger quantities might lower production costs for a period while production and transport economies are exploited. The minimum acceptable selling price for coal-to-methanol production, shown in Figure 3, is expressed

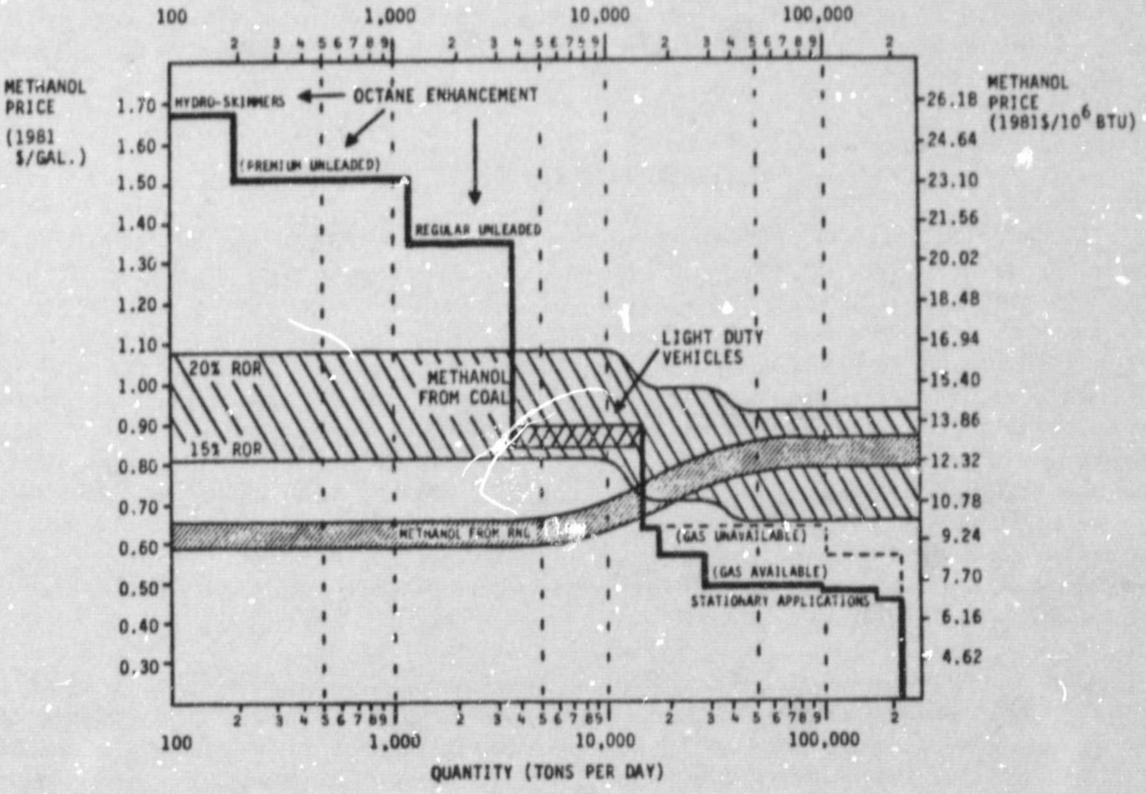

Figure 3. Methanol Fuel Markets Beyond the Year 2000 (1981 $)

as a range reflecting uncertainty about the potential economies of scale, required rates of return, and transport options. Even under the most optimistic assumptions, coal-based methanol would not be competitive in stationary applications, while in the baseline case (20% return, modest economies of scale and pipeline transport), methanol would not be competitive with gasoline until beyond the year 2000. Thus, it is not anticipated that unsubsidized coal-to-methanol plants in the United States will be initiated in this century.

Use

The dominant long-term market for methanol as a fuel, as shown in Figure 3, is in light-duty passenger vehicles. That is not to say that there will not be other important markets, but they will be much smaller in size; in this smaller but important category, methanol may be used in utilities in the period beyond the year 2000 for limited peaking requirements, and by industry and utilities as a boiler fuel in environmentally sensitive areas.

The highest value submarkets are for octane blending, but these markets are very small, totaling to no more than 2000 tons/day. Light-duty vehicles should be the next highest value market which is also small initially. Figure 3 also shows that the prospects for methanol use in stationary applications are not very optimistic in the case where natural gas is available. In fact, as strictly an energy source, methanol is not likely to compete with LNG or medium Btu gas (MBG) as a fuel source for combined-cycle plants or for repowering oil-fired boilers. There may be a small utility role for methanol in dual-fueling plants under strict control for NO_x emissions.

PUBLIC AND PRIVATE SECTOR ROLES

From California's perspective, there are two overriding motivations for examining methanol as an alternative fuel in stationary and transportation applications: security of supply and environmental improvement. However, both of these factors may not be sufficient to induce methanol implementation if their value is not sufficient to make methanol viable in specific applications. An examination was made based on the available data to see if there is justification for government intervention in the private marketplace to either facilitate or accelerate methanol production and use, given the projection of what the consequences would be of letting the market determine methanol introduction and evolution. Thus, the goal here was to determine from the data developed in the study and other sources whether a government role is justified and, if so, what the impact of government policy would be on the methanol fuel market.

The first step in determining the appropriate policies for the public sector in the evolution of methanol as a fuel in California is to examine to what degree the private market is not providing proper incentives for methanol use. Rationales for justifying a public role were examined for an oil import premium and an environmental premium based on lower emissions. Although quantitative estimates on these types of premiums are admittedly imprecise,

they do provide some rough guidelines on whether the social benefits of methanol are sufficient to justify its cost.

In areas where there was simply too much uncertainty to formulate a policy for methanol use in the state, the objective is to evaluate whether the preconditions exist in terms of efficient markets and other institutional mechanisms for the expansion of methanol-fuel use if it meets the market test. Emphasis was placed on examining mechanisms that help the market reflect the cost and benefits of methanol as they become known and that efficiently transmit them to both potential producers and consumers.

The rapid changes in events and trends in the last decade are an indication that our understanding is quite limited of how energy markets in general and international oil markets in particular will evolve. During the last 8 years since 1974, the forecasts of energy demand have changed dramatically in response to a better understanding of supply and demand elasticities, Middle East politics, and the evolving policy of the United States.

Oil Import Premium Policy

Implementing an oil import premium policy, such as a tariff on oil imports, is more efficient than subsidizing a specific option (like methanol or shale oil) in that it does not bias the selection process. Based on a recent study* which placed a bound on the likely value of a United States import premium from $8.00/bbl to $20.00/bbl, Table 2 shows the impact of the premiums on the baseline cost of gasoline. The implication is that if methanol were competitive with gasoline at $1.74 in 1990, there would be reason to believe that a national policy of imposing an import premium (for instance through a tariff) would induce a methanol market. If methanol required a gasoline price of more than $2.03/gal in 1990 (in 1981 $) to be competitive, then even a premium would not induce a methanol market. The study analysis indicates that an increase in gasoline prices of $0.19/gal (in 1981 $) does significantly accelerate the period at which methanol becomes a viable transport fuel (by about 6 years) for methanol made from remote natural

Table 2. Gasoline Prices With the United States Import Premium

Year	Baseline Gasoline Market Price, $	Gasoline with Import Premium	
		$8/bbl	$20/bbl
1990	1.55	1.74	2.03
1995	1.80	1.99	2.28

*World Oil, Energy Modeling Forum, Institute for Energy Studies, Stanford University, EMG Report 6, February 1982.

gas. For methanol from coal, the breakeven timeframe is so far in the future that an import premium would not have a significant impact.

The conclusions of this study on the issue of national security are that: (1) if there is a value ($8/bbl) above the free-market oil price to oil import reduction in the United States, there would be little impact on coal-based methanol; (2) any attempt to implement such a policy should be done at the national level, where the costs are spread among all beneficiaries; (3) an oil-import premium should be implemented in a neutral manner (e.g., oil-import tariff) to allow the market to select the best alternatives; (4) an import premium of $8/bbl would raise the retail price of gasoline about $0.19/gal, which would accelerate the over-the-road competitiveness of methanol and other synfuels 4 to 5 years if the premium were believed to be of a stable duration; (5) from a fuel security viewpoint, methanol is not significantly different from other synfuels that substitute for imported oil; and (6) within California, the value which can be justified for a California-only oil import premium is smaller because the market power component (impact of substitution on lowering the world oil price) is reduced considerably compared to the nation as a whole, as most of the benefits would accrue to others.

Environmental Policies

Another nationwide concern with special significance for California is the air-quality problem in its urban centers. In this regard, methanol does have unique properties compared to other transportation synfuels such as shale oil, Fischer-Tropsch liquids, and products of direct coal liquefaction, as well as conventional gasoline and diesel fuel. It is also clear that substitution of methanol for oil in utility applications can lead to some benefits as a result of reductions in NO_x, SO_x, and particulate emissions. The value of these benefits to the utilities, however, is not as clear.

Utilities in the South Coast Air Basin (Los Angeles and vicinity) and in the Ventura Country Air Pollution Control District (especially Southern California Edison and Los Angeles Department of Water & Power) are required to reduce their NO_x emissions by 60% by the year 1990. Use of methanol in some units could be included as part of an overall strategy to satisfy this requirement. This could lead to payment of a premium for methanol. A similar requirement is under consideration to limit SO_x emissions in the South Coast Air Basin, and there may be requirements to reduce particulate emissions.

The premiums for the values for methanol as a pollution abatement strategy would be an additive for NO_x and SO_x. Thus, the potential premium value is approximately $0.65 to $0.90/$10^6$ Btu, or about $0.05/gal of methanol. This size premium is not likely to induce use of methanol in many plants. The cost difference that has been calculated between methanol and conventional utility fuels is much larger than this value. Nevertheless, in the longer term it would be highly desirable if a market system were established to create a stable mechanism for determining the value of the premium that methanol or other clean fuels should have as part of an efficient environmental program. Based on the data that exist to date, however, implementation of a policy to internalize these environmental attributes of methanol would not significantly accelerate methanol use.

Subsidies

As far as the State of California is concerned, there is little to be gained from subsidizing production of methanol because the Federal Government has already assumed that role. Eventually it may be in California's interest to have a western coal-to-methanol project among those awarded assistance by SFC. The State can improve the likelihood of this type of project by helping prospective project sponsors and supplying data on California markets for methanol. There does not seem to be a justification, however, for any state-sponsored production subsidy to either augment or duplicate SFC's program.

The one area where the State, through its Public Utility Commission (PUC), can make a contribution to lowering the cost of methanol production is in further development and the eventual demonstration of the once-through methanol, coal-gasification, combined-cycle concept. Potential efficiency gains in the once-through process imply that a cost saving of about 20% (aside from utility financing impacts) may be possible from such a system when compared with a dedicated methanol plant. Proposed experimental programs by California utilities for development of this process should be given careful consideration by PUC.

Near-Term Programs

To improve the acceptance of methanol as a fuel, the State of California might implement the removal of institutional barriers arising from regulations and restrictions not conceived with methanol in mind. The California Energy Commission (CEC) has been active in searching for such unintended barriers and has been successful in eliminating the most important obstacles. For example, the state gasoline tax will be levied on methanol on a Btu basis equivalent to gasoline rather than on a gallon basis. Taxing methanol on a gallon basis would have penalized methanol relative to gasoline. The State has also sponsored tax credits for converting vehicles to neat-methanol use, which have been responsible for initiating fleet conversions within California. In general, CEC has been diligent in encouraging alcohol-fuel use through barrier elimination, developing test information through its alcohol fleet test program, and providing incentives for vehicle conversion.

The focal point of the State's plan currently is the $5 million program to purchase and support approximately 1000 fleet vehicles, to establish 50 to 100 commercial refueling stations in California, and to test methanol-fueled California Highway Patrol pursuit vehicles. These activities are intended to help develop market stimulus, which will eventually lead to a self-sustaining methanol fuel market. Related efforts are also under way to demonstrate methanol in heavy-duty diesel engines and in stationary applications (repowering and co-firing). These other programs for different types of applications are important to CEC's strategy of developing methanol uses that displace the majority of refined products from crude oil. The Commissions's rationale for this strategy is that an alternative fuel that only displaces gasoline, for example, could have adverse effects on the existing petroleum product slate, necessitating refinery modifications and/or relative price changes in refined products. The stated goal of these programs is to accelerate the "take-off" point for self-sustained commercial market growth.

Given the abrupt reduction in the expectation for conventional fuel prices that has occurred in the past 2 years, and the significant rise in projected cost of synfuels, it is important to assess what government programs can realistically accomplish in this environment. First, it is clear that the viability of synthetic-fuel projects has deteriorated significantly in this 2-year period, as evidenced by the cancellation or postponement of numerous synfuel projects. Second, the excess capacity in OPEC oil production makes a near-term oil disruption less likely than it was a few years ago. The net effect of these factors is that the market viability of the long-term neat methanol-fueled vehicle market supplied by western coal has been pushed back until after the year 2000 in the most likely scenarios. The major fuel producers have little incentive, in the view of this study, to move aggressively toward creating the supply and distribution network needed for the use of neat methanol as a large-scale transportation fuel in the foreseeable future. There are, however, other selected markets where methanol will be used successfully during this period: octane enhancement, some captive fleets, and limited use by utilities. Programs that are oriented toward these limited goals can be successful in the period before 1990, but not if they are expected to lead to a private passenger car market.

In stationary applications, the potential market with the greatest promise for being economically viable is overfiring with a small percentage (10% to 15%) of methanol. This concept, if successful, can lead to a justifiable premium for methanol sufficient to overcome its added cost if the capacity factors of plants constrained by NO_x emission restrictions are expanded. In effect, the value of this additional operational capacity added to the value of methanol fuel can be substantial, but it is limited to those plants that are NO_x-constrained. This study strongly supports the conducting of tests to confirm the potential performance of methanol in the overfiring mode. To be of greatest value, however, it is important for overfiring with methanol to be tested against overfiring with natural gas. A significant proportion of the benefits of overfiring may be achievable at lower cost with natural gas overfiring, which would reduce the justifiable premium for methanol. This submarket of utility operations is relatively small (1750 tons/day of methanol) compared to utility fuel use, but quite significant relative to current use of methanol as a fuel. Thus, although a major use of methanol is not anticipated as a fuel substitute for residual oil or natural gas in utilities, it may be benefically used in highly selective applications (e.g., overfiring in environmentally restricted plants).

One possible method for achieving greater use of methanol within California is for government policy to be used to promote (perhaps even require) utility applications as a means to provide a base for expanding fuel use into transportation markets. For a number of reasons, it is believed that this policy would not be a desirable means to transition to large-scale use of methanol as a transportation fuel. First, the value of methanol in transportation markets (especially octane enhancement) is considerably higher (i.e., at least double) than its value as a utility fuel. As a result, methanol will be used first in these higher value markets and will be applied only to lower value uses as the methanol competition increases production and lowers price. Second, the cost of producing methanol in large quantities will be too high to compete with conventional utility fuels. Thus, utility customers would have to pay a large premium ($3/10^6$ Btu for methanol from remote natural gas)

over current utility fuels, which cannot be justified by any realistic assessment of the benefits. Third, the experience gained in transporting, handling, purchasing, storing, and using methanol would be based on utility use, which would not carry over to transportation fuel companies. Fourth, although the quantities of fuels used by utilities are sufficiently large to utilize the output of a coal-to-methanol plant (once thought to lower cost through volume production), the cost of methanol would be considerably higher than from much smaller plants based on remote natural gas. Thus, the strategy of inducing utilities to use methanol through public policy as a means of transition to more widespread use in other applications is not attractive. This conclusion is not intended to imply that public support of programs is inappropriate to test methanol use in potentially viable utility applications, but rather that these programs should be justified based on their own merits as to their ability to benefit utilities and their customers.

One often discussed obstacle in implementing widespread use of methanol in transportation is that the retail distribution system must expand rapidly in anticipation of automobile manufacturers producing and selling neat methanol-fueled vehicles to the general public. The problem with distributing methanol is that part of the existing gasoline distribution system (seals, hoses, patches in tanks, etc.) would not be compatible with methanol use. Compounding the problem is the fact that the most recent cycle of replacements at retail outlets has been done with fiberglass tanks instead of steel, which makes the existing system even less compatible with methanol. Creating a parallel system for methanol by replacing functional equipment now used for gasoline presents a significant cost and hence an obstacle to methanol. The lead time that exists, however, before methanol can compete as a private passenger car fuel provides time to create a threshold distribution system much more efficiently. Currently in California there are approximately 18,000 retail gasoline stations supplying transportation fuels to the public. As a general rule, the tanks and pipes in these stations have an expected life of 20 years, which, with a uniform replacement rate, would imply about 900 replacements per year. Even a single company therefore could create a threshold distribution system in a short lead time. For example, if 20% of the regularly scheduled replacements (tanks, pipes, pumps) were made for methanol-compatible systems each year, that would imply approximately 150 to 180 conversions per year. Thus, if this program were started in 1990, by 1996 about 1000 systems would be in place that could be used to distribute methanol. Some cleaning of the system would have to be done when the conversion actually took place, but that would not impose a major cost. The cost of methanol-compatible systems versus conventional systems installed without this program is a crucial factor in its usefulness. The cost for replacing a tank, piping, and two pumps at a typical service station is approximately $50,000 (in 1981 $) for a fiberglass system, and somewhat less expensive for a steel system. The latter, although less expensive, has a lifetime that can be considerably smaller, depending on the climatic conditions to which it is exposed. In addition to the costs of more frequent replacements with a steel system, there are additional costs arising from station disruption and the risk of damage caused by undetected leaks. With the relatively dry climate in much of California, the added cost for methanol-compatible systems should not be great or a major impediment to methanol use. The costs of such a program would seem to be fairly modest when compared with a coal-to-methanol plant. For example, if the extra cost for a methanol-compatible system were $5,000 per installation, then 150 stations per year

would cost $750,000. Although this is not a trivial sum of money, the cost over 6 years is $4.5 million to create a threshold distribution system of 900 retail outlets, which is less than 1% of the cost of a 5000 tons/day coal-to-methanol plant. If instituted in this type of incremental fashion using the normal replacement cycle, the retail distribution barrier need not be a massive obstacle to widespread methanol use. Obviously, the transport system would involve more than the retail distribution outlets, but the delivery system is well within the capability of the private sector if the economic viability of methanol is favorable.

CONCLUSIONS

A successful strategy for making a transition to widespread use of methanol as a fuel must be consistent with the realities of the fuel market in which it must compete. It is clear that in the last year and a half, the climate for introduction of synthetic fuels has changed dramatically. In 1981, oil prices in constant dollars reached a peak from which they have since fallen approximately 20%, but even more important is the change in expectations for the future. It is widely believed that real oil prices will fall in 1983 and then remain constant in real terms through 1985 and only rise to 1981 levels by the end of the decade.

When this study was first conceptualized in 1980, the expectation was that more emphasis could be placed on actual mechanisms to implement large-scale methanol use in the next 10 to 20 years. However, as a result of changes in the oil market as well as more realistic estimates for methanol production costs, elaborate transition strategies are not possible at this time. Methanol is simply too costly for large-scale implementation (e.g., substitution for utility fuels or gasoline as a neat transportation fuel) to be feasible.

These general conclusions, and the more specific ones that follow, represent the best judgment of the study's authors based on the data and analysis incorporated in Volume II: Technical Report. Not every finding can be rigorously proven, because this subject requires some judgment on future behavior of fuel markets, technologies, and government policy, which cannot be known with certainty. Thus, the conclusions are offered as logical interpretations of the existing data.

Supply

- The sources of methanol in the near term will be dominated by natural gas as the feedstock. After deregulation of pipeline gas, no new plants are likely to be built based on this resource, although it is anticipated that most existing plants will continue to operate for the rest of the 1980s and early 1990s.

- New plants throughout the world, already under construction or in planning stages using remote natural gas, will be sufficient to satisfy modest fuels demands through 1987.

- The projected excess methanol production capacity relative to chemical market demands through 1987 could exceed 1 billion gal/year.

- While large quantities of western coals exist that are potentially available for methanol conversion for use in California (in particular, the subbituminous coals of Black Mesa, San Juan, Yampa, and Powder River), substantial support including price supports and loan guarantees would be required to be viable.

- In the near-term and transition periods, the likely quantities of methanol demanded could not justify a methanol pipeline from western coal fields.

- Where large volumes or distances are required, there is a clear economic advantage of transporting methanol by means of tankers or pipelines when compared with rail or truck.

- Indigenous California resources are either too limited in supply (bioenergy, petroleum coke) or too expensive (heavy oil in rock) to support a major transition to methanol fuel within the State. Small selective markets, however, will probably be served by these in-state resources.

- Existing methanol producers will compete successfully in chemical markets at production costs of $0.67/gal through 1987.

- There is sufficient remote gas to supply California demands for the next 15 years at prices that would undercut any unsubsidized coal-to-methanol project.

- One of the implications of SFC's proposed support of coal-to-methanol plants may be to displace methanol produced by the United States chemical industry.

- Methanol producers should be able to compete for use of some remote natural gas with LNG producers given that methanol has a higher value per Btu in transportation applications than LNG and methanol has a production advantage in smaller gas reserves.

Demand

- The stationary applications market will be small. If the dual-fueling concept can be demonstrated to work effectively and plants currently limited in operation by NO_x regulations can be operated at rated capacity using 10% methanol, the implied premium may be sufficient to make methanol competitive in these plants. The maximum market in this case is only 1500 tons/day, and the dual-fueling technology is yet to be demonstrated at full scale.

- No economic use exists for methanol as a fuel for repowering boilers, even with the credit for eliminating the need for environmental control technology.

- A small market will exist for methanol as a gasoline blending agent by the smaller (topping and hydro-skimming) refineries. This market seems to be presently existent at current methanol prices.

- Blends (low-level) have a maximum market in California of approximately 4000 tons/day of methanol, but it is limited by the availablitiy of tertiary butyl alcohol. Thus, the actual demand will probably be small in the near term.

- Neat methanol-fueled vehicles will experience a slow growth rate because they will not achieve even a slight over-the-road cost advantage (based on remote natural gas-based methanol) until after 1990, although this advantage will increase over time (coal-based methanol would not be competitive until beyond 2000).

- If methanol-fueled vehicle use were to grow as quickly as the diesel market, which is doubtful, the proportion by the year 2000 would be about 12%, which would present a level of demand consistent with remote natural gas-based methanol from the Pacific Rim.

- With likely improvements in conventional gasoline vehicles, projected fuel factors as low as 1.3 for neat methanol-fueled vehicles are unrealistic in the long term. Potential improvement from a 1.7 fuel factor (existing technology) to a 1.6 fuel factor in the long term (advanced technology) is possible.

Strategy

- Methanol availability in the long term can be effectively aided by the State of California by facilitating methanol transport by tanker and pipeline. In the near term, port facilities at Long Beach and San Francisco Bay, and at coastal power plants are sufficient for any anticipated needs. In the long term, pipelines from western coalfields will be crucial links in efficient systems if the methanol demand expands.

- Given proper incentives to act, utilities would need a 4- to 8-year development period for widespread conversion and use. The transportation sector would require a 20-year period. At current prices, however, there is little incentive to begin this process.

- Artificial demand created by regulations to induce greatly increased methanol use (i.e., 50,000 tons/day) will lead to rising methanol supply costs as longer transport and higher remote gas collection costs are incurred, and thus would be self-defeating.

- Attempts to favor the use of in-state feedstocks will only slow the methanol transition by raising methanol production costs.

- Methanol can form part of an effective strategy for the control of photochemical smog and fuel diversification after the year 2000.

- Even in the absence of government intervention, the private sector is fully capable of implementing large-scale use of neat methanol as a transportation fuel when it becomes viable.

- There is no evidence that the "derived likely roles" for methanol resulting from government policy to correct externalities significantly affects the free market rate of methanol use in the period through 1995.

RECOMMENDATIONS

- Technology development should be pursued to improve methanol viability in the long term. Production technologies (e.g., co-production, once-through concepts), utilization technologies (e.g., advanced neat methanol automobile engines, methanol overfiring), and demonstrations (e.g., California fleet program) can contribute to improving the viability of methanol versus conventional fuels.

- Further work may be done to improve the demand analysis of methanol in selective target markets where methanol may command a premium value: performance automobiles, selected fleet operators, specific refiners, etc.

- In the policy area, the most productive activities would be to create better institutions to take into account the environmental value of methanol (e.g., markets for licenses to emit NO_x or SO_x).

- The selective markets that seem viable in the near term (octane enhancements, utility boiler overfiring, selected centrally-fueled fleet operators) should be pursued to gain the experience in handling, maintaining, and operating with methanol fuels.

- Policies that attempt to rapidly expand methanol use through mandates should not be enacted because they would be self-defeating. Relatively inexpensive feedstocks cannot supply a large methanol fuel market, opportunities for technological advance would be lost, and the chance to use the normal replacement cycle for distribution systems could not be taken advantage of if methanol were forced into the fuel market too rapidly.

SECTION I

INTRODUCTION

The California Methanol Assessment was organized by the Jet Propulsion Laboratory (JPL) of the California Institute of Technology (Caltech) through an interagency agreement with the National Aeronautics and Space Administration. The study was a joint effort by JPL and the Caltech Division of Chemistry and Chemical Engineering and was sponsored by various private companies and public agencies who are potential stakeholders in methanol use, production, and distribution.[1] State-of-the-art technical data were synthesized from these sponsors and other sources, and then analyzed for California markets to determine the appropriate roles that methanol can play and the efforts that are warranted to ensure an efficient and timely transition into the marketplace.

Methanol has many potential uses as a fuel in stationary and transportation applications in California. There are unique benefits that could be derived from widespread use of methanol in California because of the state's air-quality problems, its number of potential feedstock sources for methanol, and its high vunerability to oil disruptions given relatively high oil use in utilities and a population highly dependent on automobile transportation. Relative to the use of conventional fuels, use of methanol could reduce the emissions of sulfur oxide (SO_x) and nitrogen oxide (NO_x) into the atmosphere of urban centers.

A. STATEMENT OF THE PROBLEM

The barrier to widespread methanol use as a fuel has been characterized by potential participants and other knowledgeable observers of the methanol market as a problem of the nature of "the chicken or the egg." By this they mean that neither the production technology nor efficient utilization technology can be established in anticipation of the other; that is:

> Potential methanol producers will not make the large investments necessary in the production and distribution system until they have large markets to supply, and the automobile industry is reluctant to manufacture vehicles for which there is virtually no distribution network or fuel available.

The implication of this statement is that both the fuel and automobile industries must act simultaneously on a large scale to make methanol fuel viable. The issue of scale is potentially important, as it has been suggested that: (1) methanol must ultimately be made from coal in large (25,000 tons/day or larger) western minemouth plants, (2) methanol must be pipelined to end-use markets in high-volume pipelines (50,000 tons/day), (3) automobile manufacturers must mass-produce (at least 30,000 vehicles per year) optimized

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[1]The sponsors of the California Methanol Assessment are listed in the Acknowledgments.

methanol vehicles to achieve end-use efficiencies, and (4) potential vehicle buyers must see an established fuel distribution network before they will purchase neat methanol-fueled vehicles. Each point represents a hypothesis that can be evaluated to determine if it is a critical element in the viability of methanol fuel. Once this basic determination is made of what characterizes a mature methanol delivery system, the real problem remains: to find transition mechanisms to facilitate an efficient evolution of the methanol fuel market.

The particular focus of this study has been to determine if there are useful transition-period (defined in this study as 1982-1995) strategies, policies, research activities, regulatory changes, or avenues of cooperation among the participants in the methanol market that would facilitate methanol achieving its longer-term role (1995-2000) more efficiently. This is a very difficult problem and challenges fuel producers, automobile manufactors, fuel distributors, end users, government agencies, and research organizations to determine sensible processes and policies within a timeframe that will allow methanol to be efficiently available for future demands.

B. STUDY GOALS AND APPROACH

The goals of this research effort have been to: (1) synthesize, evaluate, and document key technical issues (e.g., neat methanol engine efficiency, economies of scale in methanol production, environmental effects of methanol use), (2) identify the essential features of a mature methanol fuel industry if it should develop, (3) identify and characterize potential near-term and mid-term methanol fuel markets, (4) evaluate whether there is a viable transition strategy, and (5) determine if selected policy alternatives can significantly alter the transition period. Overriding all the specific goals above is the goal of identifying the next steps in methanol market evaluation for each of the key participants (producers, users, equipment manufacturers, distributors, regulators, legislators). It is not the intent of this study to offer a blueprint of the entire transition process because each successive step is contingent upon information developed along the way. The uncertainties are too great to compound them in series by laying out elaborate scenarios over the next 20 years. Instead, the intent has been to focus on the next steps and then to look for flexible processes or mechanisms which establish the preconditions for an efficient market to operate. If uncertainties are resolved satisfactorily, then the market will respond accordingly.

The framework used in this study is based on a few key premises: (1) private markets will be the ultimate test of whether methanol becomes an important fuel source; (2) there are some strong technology and cost uncertainties in methanol and other synfuels that are not resolvable at this time; (3) there are institutional barriers and externalities that prevent existing market forces from properly valuing all the attributes of synfuel alternatives; (4) there are positive steps that can be taken now to establish the preconditions for an efficient methanol market; (5) some dominant aspects of the transition path (e.g., where potential fuel costs, such as methanol and M-gas, are closely related) can be specified now because, in a relative sense, they are insensitive to many technical and market uncertainties; and

(6) California has unique fuel requirements because of environmental problems that make it a valuable study focus.

The basic framework of the study was constructed by assembling as sponsor organizations, which are either involved now or would be instrumental in a successful methanol market. The intent of this approach has been to work directly with many of the most knowledgeable sources of information on: fuel production (ARCO, Chevron, Conoco, Exxon, Phillips, Sun, and Texaco), chemical methanol (du Pont), utility potential (EPRI, PG&E, SCE), automobile technology (Ford, General Motors), national synfuel incentives (Synthetic Fuel Corporation), state governmental roles (California Energy Commission), and production equipment (Litton), and to synthesize the collective wisdom of this group and subject it to analysis by JPL teams. Thus, the emphasis has not been placed on generating new basic data, but rather on resolving conflicting information, performing more detailed market analysis in California submarkets than has been published to date, and synthesizing this information into a California strategy.

Although many sponsors were involved in supporting this study, providing data, and reviewing its findings, the conclusions are not necessarily agreed upon by each of the sponsors. This document does <u>not</u> represent a consensus view in any respect; in fact, with such a diverse set of sponsors, it is not surprising that there are many divergent viewpoints (see Appendix B of the Technical Report for sponsor comments).

Although the focus of the study is on methanol utilization within California, examination of methanol production, however, was not so constrained, as it would have artificially distorted the results. This broader view was given to policy issues as well, and includes an examination of national policy toward synfuels, but concentrates on options that can be implemented at the state level. Thus, although it is recognized that there is a world market for methanol with inherent supply/demand implications, the study has concentrated on California's particular markets, regulations, air quality problems, and competitive environment.

C. ORGANIZATION

This Summary Report contains eight sections that are drawn from the <u>California Methanol Assessment - Volume II, Technical Report</u>, JPL Publication 83-18, JPL Report 5030-562, March 1983. The technical chapters deal with particular subjects (e.g., feedstocks, methanol production, transport, utilization in vehicles, etc.) throughout the analysis period from 1982 through the year 2000, covering the pertinent aspects of technology, economics, and policy. In this Summary Report, these topic areas are synthesized by timeframe (near-term industry, transition paths, and long-term markets), and cross-cutting topics (policies, environmental implications). The choice of the specific time period used for near-term (1982-1987), transition-period (1988-1997), and long-term (1997-beyond) market analyses was made partly for convenience in organizing the discussion and partly because of real constraints in the evolution of methanol as a fuel. For example, the near-term period of 5 years is short enough so that changes in methanol production capacity can be estimated reasonably accurately (plants are already in planning or construction

stages) and the state of utilization technology is relatively fixed. The transition period from 1988 to 1997 is the timeframe in which methanol use would have to expand rapidly if it were to make a significant impact on fuel markets by the turn of the century. Finally, the long-term market is simply defined as beyond 1997 because that is a period within which some results would have to be realized to motivate action now in planning, technology development, and policy implementation.

An array of individuals representing a broad spectrum of disciplines contributed to this study, including: chemical engineering, petroleum engineering, policy analysis, and thermodynamics. Their work was synthesized into an assessment framework and reviewed both internally at JPL and by the Technical Advisory Group, composed of representatives of the sponsors. A key feature of the assessment approach was that information was exchanged and discussed by the Technical Advisory Group in three 2-day meetings held to review drafts of the interim and final reports. Although agreement was not reached on all points, these meetings provided an opportunity to discuss specific issues from the perspective of companies who are or might be potentially involved in methanol production, distribution, and use.

D. STATUS OF THE CURRENT UNITED STATES METHANOL INDUSTRY

1. Background

At the turn of the last century, methanol was exclusively produced by extracting it from pyroligneous liquor (obtained during the destructive distillation of wood). In 1926, synthetic methanol from Germany entered the United States market at two-thirds of the price of natural methanol. The average cost in New York in 1926 was $0.40/gal for natural methanol. Facing this threat, the wood distillers managed to have the tariff increased to $0.18 and to have legislation passed to the effect that only natural gas could be used as a denaturant, which guaranteed them a third of the market at that time. In 1926, the production of synthetic methanol began in the United States, and production has grown steadily since. Increasing production capacity and competition eventually brought the price down and stabilized it at around $0.30/gal. Early plants were designed in conjunction with other plants to make use of carbon-dioxide or hydrogen byproducts.

Interestingly enough, synthesis gas was originally made from coal. A major process for the gasification of coal is the Winkler process, discovered in Germany in 1922. Later, however, the feedstock was shifted to oil and then to natural gas as large petroleum discoveries were made and the cost of these carbon sources dropped. Natural gas was particularly appealing because of its low sulfur content and federally-regulated low prices. By the 1960s, synthetic methanol in the United States was almost entirely manufactured from natural gas by a high-pressure process similar to that used to produce ammonia. In this high-pressure process, pressurized synthesis gas is normally made by the reforming of natural gas and consists of a mixture of carbon monoxide, carbon dixoide, and hydrogen. Because natural gas contains more than the ideal amount of hydrogen, carbon dixoide is usually added to balance the excess hydrogen. As a result, methanol producers usually located their plants close to ammonia plants, because large amounts of carbon dioxide

are removed from the synthesis gases used to produce ammonia. In a typical process, the above-mentioned synthesis gas is desulfurized, cooled, compressed, mixed with recycled gas, and passed to the methanol converter. Zinc chromium oxide catalysts are used in the conversion of synthesis gas to methanol. The methanol-containing gases formed are cooled, condensed, and purified.

In 1967, Imperical Chemical Industries introduced a low pressure synthesis process based on newly developed copper-based catalysts that are much more reactive than the zinc chromium-based catalysts. The lower pressures and temperatures allowed by this process lower the cost of production substantially. The price of methanol, in fact, dropped from $0.23/gal in 1971 to around $0.10/gal in 1972-1973 (see Table 1-1).

2. Present and Future Demands

The pattern of methanol use in the United States has also changed somewhat over time in response to new uses being found for methanol in

Table 1-1. HISTORICAL U.S. METHANOL PRODUCTION AND PRICES

YEAR	ANNUAL PRODUCTION (10^6 gal)	PRICE[a] (¢/gal)
1965	432	27
1967	517	26.7
1968	575	25
1969	633	25.4
1970	743	26.7
1971	755	22.8
1972	897	10.7
1973	1064	12.5
1974	1036	20.9
1975	780	39
1976	940	39
1977	973	39
1978	1006	43.1
1979	1100	44
1980	1070	62
1981	1260	75
1982[b]	1260	70-75

[a]Wholesale price in current year dollars.
[b]First quarter.

SOURCES: Chemical and Engineering News 1/22/79, 1/28/80, 1/26/82, 3/29/82; Predicasts Inc.'s Basebook; U.S. Department of Commerce; Data Resources, Inc.

chemical and fuel applications. Figure 1-1 indicates the pattern of use in 1980, which is representative of methanol demands for the late seventies.

In 1980, the fuel use of methanol in the United States was under 100 million gallons per year and a very small proportion (about 6%) of total methanol demand. This usage pattern can change quite rapidly, however, given that the potential fuel uses of methanol are so large relative to its chemical uses. Currently, methanol is used primarily as a feedstock in the production of resins, glues, and plastics.

The largest single methanol market is use of methanol-based formaldehyde in the production of resins. In a typical year, ureau formaldehyde resins take about 25% of formaldehyde output and phenol formaldehyde resins nearly as much. Housing is the biggest single user of these materials. Consequently, methanol production depends very strongly on movements in the housing market. Methanol used for the production of formaldehyde constituted only 30% of methanol production in 1981. This percentage has dropped from 41% in 1980 due to the fact that the housing market has declined substantially.

It should be noted that, in general, modernization and expansion of existing houses use a higher proportion of plywood and particle board than

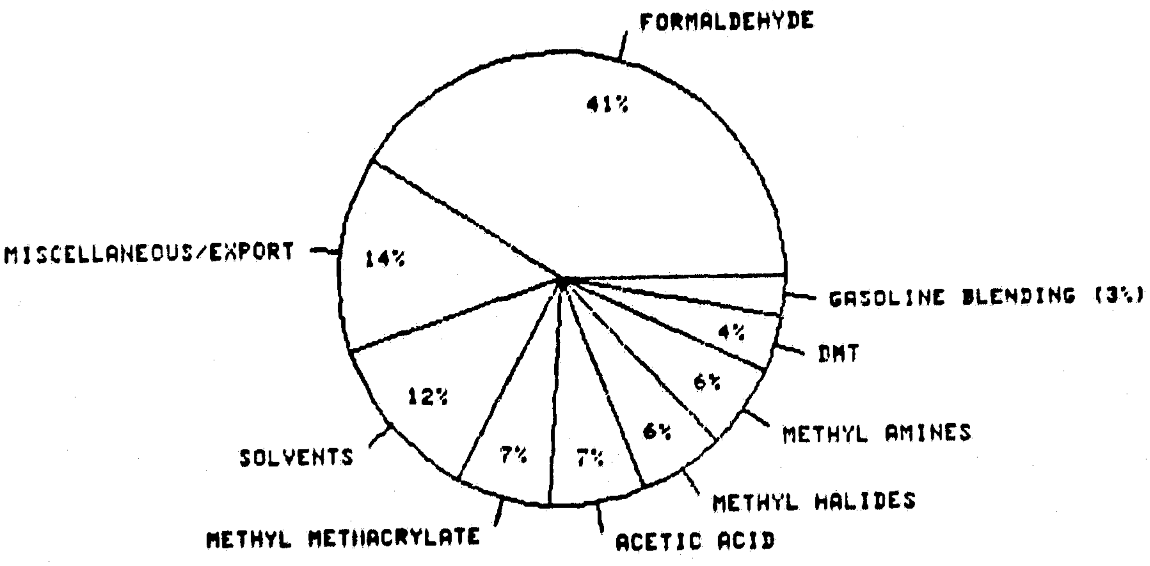

Figure 1-1. 1980 U.S. METHANOL DEMANDS (1980 total: 1070 10^6 gal)

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does new construction. Therefore, the demand for resin-based housing materials increases when fewer new houses are built and there is instead more modernization and expansion. The demand for formaldehyde in construction of mobile homes and other semipermanent living quarters is not counted in housing starts. It is possible there could be a moderately strong demand for plywood and particle board if building trends shift toward these lower-cost living quarters.

The second largest chemical derivative market for methanol is methyl methacrylate (MMA). The largest end use of this chemical is acrylic sheet production; other end uses are surface-coating resins and molding and extrusion powders. Dimethyl terephthalate (DMT) is used in the manufacture of polyester fibers. Except for minor quantities used in the preparation of herbicides, resins for adhesives, printing inks, and specialty coatings, most are used to make polyester films and thermoplastic polyester engineering plastics. The other major current use of methanol is for production of acetic acid. The largest end uses for acetic acid are vinyl acetate monomer, which accounted for 44% of acetic acid consumption in 1978, and acetic anhydride, which accounted for 28%. In 1978, about 17% of the acetic acid produced was based on methanol, a percentage which is expected to grow substantially. During the 1979-82 period, exports averaged 70 10^6 gal/year and imports were approximately 40 10^6 gal/year. The future growth of chemical markets was not examined in detail because it is not critical to the analysis of the potential for methanol use in California. Other studies were surveyed and their conclusions are summarized in Table 1-2.

The most important growth market for U.S. chemical uses of methanol is as a feedstock in acetic acid production, where it will likely capture a large

Table 1-2. CURRENT AND PROJECTED DEMAND FOR CHEMICAL METHANOL APPLICATIONS (10^9 gal/year)

	1980	1985	1990	1995	2000
Formaldehyde	0.43	0.44-0.79	0.49-0.97	0.56-1.20	0.63-1.46
Solvents	0.13	0.10-0.14	0.12-0.17	0.14-0.21	0.16-0.26
DMT	0.04	0.04-0.05	0.05-0.07	0.06-0.07	0.06-0.08
Acetic Acid	0.07	0.14-0.20	0.19-0.29	0.26-0.46	0.35-0.74
Others	0.37	0.28-0.55	0.33-0.064	0.39-0.77	0.47-0.92
MTBE & other Fuel Additives	0.03	0.18-0.30	0.07-0.53	0.17-0.53	0.17-0.53
Total	1.07	1.18-2.03	1.35-2.67	1.58-3.24	1.84-3.99

SOURCES: Hagler-Bailey, The Emerging U.S. Methanol Industry; "New Prospects for Methanol and Opportunities for Developing Countries," World Book.

share of the market because methanol is lower in cost than ethylene and butane feedstocks. Other growth areas are in the production of a single-cell protein, which will probably develop in Europe but not be a factor in U.S. methanol demand. The development of the fuel additive market, specifically methyl tertiary butyl ether (MTBE), is of course very promising and has been considered directly in the California assessment. The national projection in Table 1-2 includes MTBE. The study analysis of octane enhancement was made only for the California market, which is quite different from the market in other parts of the country.

3. Near-Term Supply Outlook

As shown in Table 1-3 (page 1-9), there is a significant amount of U.S. methanol capacity to be added during the 1980s (about 20%, or a $375 \cdot 10^6$/year increase from 1982 through 1988). When this capacity increase is compared with free world capacity additions of 2.8 10^9 gal/year between 1982 and 1988 (see Table 7-3 of the Technical Report), it is clear that the production capability is growing rapidly compared to traditional chemical demands. In fact, by 1985, the excess production capacity will be over 10^9 gal/year worldwide if no fuel markets develop. This balance is shown in Table 1-4. Obviously, this situation will change somewhat over time. If the expectation of this oversupply continues, some of the proposed plants may be deferred or cancelled and downward pressure on prices may expand methanol use as an octane enhancer or chemical feedstock.

Table 1-3. U.S. METHANOL PRODUCTION CAPACITY (10^6 gal/year)

PRODUCER	1980	1981	1982	1983	1984	1985	1986	1987	1988
AIR PRODUCTS Pensacola, LA	50	50	60	60	60	60	60	60	60
ALLEMANIA CHEM. Plaquemine, LA	100	130	130	130	130	130	130	130	130
ARCO CHEM. Gulf Coast	---	---	---	200	200	200	200	200	200
BORDEN, INC. Geisman, LA	160	180	180	180	180	180	180	180	180
CELANESE CORP Bishop, TX Clear Lake, TX	375	385	385	385	385	385	385	385	385
DUPONT Beaumont, TX Dear Park, TX	340	450	450	450	450	450	450	450	450
EASTMAN CHEM.	---	---	---	---	50	50	50	50	50
GEORGIA PACIFIC Plaquemine, LA	120	125	125	125	125	125	125	125	125
GETTY OIL	---	---	---	100	100	100	100	100	100
MONSANTO Texas City, TX	100	100	100	100	100	100	100	100	100
TENNECO, INC. Houston, TX	80	82	130	130	130	130	130	130	130
Total U.S.	1,325	1,502	1,560	1,860	1,910	1,910	1,910	1,910	1,910
Other Free World	2,280	2,280	2,740	2,885	3,545	4,415	5,085	5,415	5,585
TOTAL	3,605	3,782	4,300	4,745	5,455	6,325	6,995	7,325	7,495

SOURCES: Conoco, "The Production, Economics, and Marketing of Methanol," presentation to General Motors Corp., March 1982; Energy Modeling Forum, "Energy Modeling Forecast," World Oil, EMF Report 6, Stanford University, Stanford, Calif., Feb. 1982.

Table 1-4. FREE WORLD METHANOL BALANCE 1981-1987 (10^9 gal/year)

	1981	1982	1983	1984	1985	1986	1987
Existing Production	3.11	3.11	3.22	3.22	3.22	3.22	3.22
Effective New Capacity (cumulative)	--	0.3	0.7	1.2	1.86	2.43	2.76
Effective Production	3.22	3.52	3.92	4.42	5.08	5.64	5.98
Free World Imports	0.03	0.07	0.13	0.01	0.17	0.17	0.17
Production & Imports	3.25	3.59	4.02	4.55	5.25	5.71	6.15
Consumption	2.91	3.47	3.74	3.97	4.17	4.30	4.47
Balance	0.34	0.12	0.28	0.58	1.08	1.51	1.68

SOURCE: Conoco, "The Production, Economics, and Marketing of Methanol," presentation to General Motors Corp., March 1982.

SECTION II

NEAR-TERM METHANOL INDUSTRY

An effort of this study has been to examine the possible transition paths of methanol into long-term fuel and stationary source markets. Therefore, this study looks more deeply than other nonproprietary studies at the submarkets in transportation, utilities, and industry that could be important in building the supply, production, and delivery infrastructure necessary for use of methanol as a fuel. For example, in the transportation fuel market, octane demand in California is examined as a complex market in itself. This point of view is quite different for the large refiners and the independents in terms of the value each would place on methanol for octane enhancement. Similarly, in the case of utilities, an attempt has been made to carefully differentiate the value of methanol in various types of generating units and under a number of environmental conditions and regulations. The results, when aggregated across the market sectors, provide the framework for structuring a transition strategy.

The study has also taken a fairly detailed look at the methanol production industry in the nearer term (1982-1987), as this period may also be crucial to a transition strategy. This period is significant because methanol production is already in a period of transition. The deregulation of natural gas now in progress will greatly alter the structure of methanol supply in the long run and may lead to significant price changes in the near term.

This section describes the study-based interpretation of the projected methanol industry evolution during the period from 1982 through 1987. This time period is important because it is a period in which major capital stock changes in production and end-use sytems will be difficult to make.

A. NEAR-TERM PRODUCTION OPTIONS AND COSTS

As described in Section I, the methanol supply industry is already in a transition period. Adding to the progressing deregulation of natural gas and a worldwide oversupply of methanol (see Table 1-4), there is a prospect for coal-based methanol plants supported by the Synthetic Fuels Corporation (SFC). Also, there is much uncertainty surrounding the near-term structure of the methanol supply industry.

Of particular interest to this analysis is the production cost of the marginal supplier[2] of methanol in both the chemical and fuel markets. It is the selling price of the marginal supplier that establishes the price observed in the market. There may be more efficient producers, some producers with access to cheaper feedstocks, or others with fully amortized plants that could undercut the marginal producer, but they will sell at the marginal price established in the market. The nearer-term supply issue has been examined

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[2]A supplier whose product is or is not cost-effective to produce depending on minor fluctuations in production costs and market rates.

here by making estimates of the production costs of various classes of producers to determine the marginal production price in the mid to late 1980s.

Three possible marginal production sources are (1) methanol from conventional natural gas plants with unregulated gas feedstock cost, (2) new floating barge natural gas plants, or (3) Synthetic Fuel Corporation-supported coal-to-methanol plants. As a basis of comparison,[3] 1987 was selected as the year of commercial operation for all three types of plants. By this time period, a number of significant events will influence the methanol industry:

(1) By 1985, U.S. natural gas will for the most part be deregulated and will move toward parity with residual oil prices at the point of use of natural gas. For California, this pricing will be based upon 0.25% or 0.5% sulfur fuel oil, depending upon the environmental requirements within the state. In the study's baseline scenario, this is expected to be in the $4.75 to $5.00 per million Btu range in 1987 (in 1981 dollars).

(2) Contracts for inexpensive natural gas, supplying the conventional feedstock for U.S. methanol, will virtually all have expired by 1985-86. As a result, domestic producers will be paying market prices for feedstock natural gas.

(3) There will be excess capacity in methanol production to supply traditional chemical market uses. Even if demands in traditional uses like formaldehyde return to pre-recession levels as the housing industry expands, the 1985 excess supply capacity will probably exceed 10^9 gal/year in free world markets (unless fuel uses expand).

1. Existing United States-Based Natural Gas-To-Methanol Plants

The most profound impact of the above changes will be on the existing U.S. methanol supply industry, which will be operating virtually 100% on market natural gas in 1987. Because the investment in these plants is sunk and some are undoubtedly fully amortized, the decision to maintain operations will be a function of whether the incremental capital costs (retrofits for older high-pressure plants and working capital requirements), operating costs, and some contribution to company overhead and profit can be covered by selling at the market-determined price. In order to quantitatively evaluate this supply source, the minimum required selling price to cover the working capital requirements, feedstock costs and operating costs has been calculated. Given the very modest risks involved in this type of operation, a rate-of-return of 15% after taxes on the working capital requirement was assumed. Feedstock and selling prices were both assumed to escalate at 8% in nominal terms starting in 1987. For this case, retrofit costs for improving plant efficiency were not examined. Given these assumptions and others documented in the Technical

[3]Other standard assumptions on these cases are detailed in the Production Cost section of the Technical Report, Chapter 4.

Report,[4] it was concluded that production cost would be $0.76 per gallon at the plant gate in 1981 dollars. At market prices below this level, it would be more profitable for the companies in question to simply shut down. Another implication of the analysis of methanol production from natural gas feedstocks is that it would not be expected for any new capacities to be added that relied on residual oil parity-priced natural gas.

2. Barge-Mounted Methanol Plants

Barge-mounted methanol plants are another interesting production source which could be the marginal methanol producer in 1987. These plants are fully self-contained units which are constructed in shipyards and towed to their operating location. A number of plant cost and operating cost estimates made by Swedyards, Litton, Mitsui, and Nissko Iwai has been considered here in evaluating the barge-mounted concept.[5] A product cost estimate of $183.3/year in millions of 1981$ is a synthesis of this data. Given that this concept is not the standard operating procedure within the industry, it will require some risk premium compared to conventional plant investments. It was assumed a 20% after-tax (nominal) return would be required, although a sensitivity analysis at a 25% rate of return was also made. In addition, it was assumed that both feedstock and product price would escalate at 8% (2% above inflation) for the life of the plant. The key assumption, however, is that remote natural gas would be available at prices far below "market" gas, which has both access to a pipeline transport system and end-use demand. Two plant locations are of particular interest in this timeframe: Cook Inlet and Indonesia. There are many other possible plant locations, but these two serve to illustrate the impacts of different transport costs and the impact of the duty on imported chemical methanol. For ease of comparison, it has been assumed that plant capital costs and operating costs are the same for both locations.[6] The major differences arise in transportation cost, with Indonesian methanol covering a much longer distance (partially offset in transport cost by using foreign carriers) to an assumed destination at Long Beach, California. Another possible difference in methanol production costs between these locations is the feedstock cost. Certainly, even though the gas used would not have an oil-based parity price, it would have to cover the collection costs as well as the owner's opportunity costs for holding the gas in the ground for possible sale later into a future pipeline or for local use. It is calculated that a minimum feedstock price in Cook Inlet is around $1.00 per million Btu, given that collection costs are moderate and the potential for a pipeline is very remote. The case of feedstock at $1.50 per million Btu was also considered. Natural gas in Indonesia may be more

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[4]Primary assumptions are for a 2000-ton/day plant operating at 65% efficiency with an annual operating cost of $189.3/year in millions of 1981$ and a working capital requirement of $39 million, all in 1981 dollars.

[5]See Technical Report (Chapter 4.B.2) for a discussion of barge-mounted methanol plants.

[6]For a 2000-ton/day plant, $290 million in capital cost has been assumed and $22 million per year in operating cost, all in 1981 dollars.

expensive to collect and transport to the plant given less development of a collection system, and thus feedstock prices would be expected in the $1.50 to $2.00 per million Btu range. Table 2-1 summarizes the barge-mounted methanol cases.

The implications of these cost projections are that foreign remote natural gas-to-methanol could compete on the West Coast for fuel, but not in the Gulf Coast for chemical markets. If one were to add an 18% duty to the Indonesian projections in Table 2-1, and the added transport cost to the Gulf, it would make Indonesian methanol uncompetitive with Gulf Coast methanol in chemical uses. The Cook Inlet option is particularly interesting because with lower transport costs than from Indonesia, possibly lower gathering and collection costs, and the absence of any duty for an American producer, it would appear to have a competitive edge. If the required rate of return were higher than that assumed above as a result of some risk perception, it would somewhat erode this advantage. At a 25% return on 100% equity, for example, the initial price would rise $0.06 per gallon for all cases, making the delivered minimum price of Cook Inlet methanol very close to that of existing producers.

3. Synthetic Fuels Corporation-Supported Plants

A third candidate for the marginal production source in the late 1980s is a coal-based methanol plant supported by a SFC loan and/or price guarantees. As an illustrative case for coal-to-methanol, a western-sited plant utilizing the Lurgi Dry Bottom Gasification Technology is assumed (it is a commercial technology which is consistent with a late 1980s operation date). It is further assumed that the plant is scaled to 4000 ton/day to take advantage of significant economies of scale up to one full production train. Given SFC participation, it is assumed that this plant could obtain significant leveraged financing. With 60% debt financing at 16% interest, and a 25% after-tax return on the 40% equity participation, the project would be financed at below market rates, which would significantly lower its cost of construction. Even given this favorable financing at subsidized rates, it is estimated that

Table 2-1. BARGE-MOUNTED METHANOL PRODUCTION AND TRANSPORTATION COSTS (1981$/gal)

	COOK INLET FEEDSTOCK COST ($/10^6 Btu)		INDONESIA FEEDSTOCK COST ($/10^6 Btu)	
	1.00	1.50	1.50	2.00
PLANT GATE COST	0.58	0.64	0.64	0.70
TRANSPORTATION (to Long Beach)	0.05	0.05	0.12	0.12
TOTAL	0.63	0.69	0.76	0.82

the initial required selling price would be $0.78 per gallon at the plant gate.[7] With the most favorable transportation system (pipeline), it would require a price of $0.82 per gallon delivered to a California central distribution point. With rail transport of methanol, coal-to-methanol would be prohibitively expensive ($0.96 per gallon).

A few points are important concerning this particular option. First, only a subsidized venture could achieve this type of leveraged financing in the near future. There are significant risks in both the construction of such a plant at a western minemouth site and the marketability of such a large quantity of methanol relative to traditional markets. Second, there has been a specific focus on the western region because this is a California study. A coal-based methanol plant could probably be constructed more cheaply (as much as 20-25%) in Texas or Illinois, which could lower the product cost considerably (as much as 6-8 cents per gallon, even allowing for higher delivered coal costs). Thus, from a national perspective, the options for coal-to-methanol are somewhat different than from the California perspective.

4. Near-Term Production Summary

The basic conclusion of the near-term production cost analysis is that the existing U.S. methanol production industry will most likely remain quite viable, at least through 1990. A year ago this prospect seemed quite remote. The key change is the moderation of expected residual oil prices to which pipeline natural gas is expected to rise. At expected natural gas prices, Gulf Coast producers can compete successfully with new foreign sources once transport and the chemical methanol import duty are added. Some existing or nearly completed foreign plants in Canada and Mexico will probably be able to undercut domestic producers slightly if their natural gas feedstock cost is significantly below pipeline gas, but this competition will not affect most of the existing U.S. producers. A rapid run-up in oil prices in the mid 1980s would, of course, significantly change this scenario. Natural gas prices would tend to rise with oil prices (residual oil) and make foreign competition much more vigorous.

An implication of the study baseline expectations is that the domestic industry will tend to maintain its market for chemical applications. Even the barge-mounted plant in Cook Inlet, which may be one of the less expensive new supply source cases, would have a production cost of $0.58 per gallon delivered by tanker to the Gulf Coast. When one also considers that the existing domestic producers have considerable marketing ties and, in some cases, vertically integrated operations, the prospect of this scenario is enhanced. Thus, if barge-mounted plants are to be introduced in Cook Inlet, it will be to service the fuel industry on the West Coast. However, methanol prices will tend to be at parity with Gulf Coast prices, less the added transportation cost. Thus, existing natural gas plants using pipeline gas are

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[7]The $0.78/gal price would then have to escalate at 8% annually over the project lifetime (or 2% in real terms) to yield the assumed rate of return.

the marginal production source and hence will, given expected demands, establish the market price.

Even with SFC loan guarantees, western coal-to-methanol plants will probably not be competitive with either existing producers, remote gas-to-methanol from Cook Inlet, or methanol plants in Canada and Mexico, based on non-pipeline gas in the 1980s. The premium for building such a capital-intensive plant in areas without a fully developed infrastructure is just too large when the other uncertainties are considered. Thus, it is more likely that any U.S. coal-to-methanol plants started in the 1980s will be subsidized and/or built in more developed areas than the western coal fields.

A point should also be made in this section on SFC's role in this near-term market. The situation in methanol production is quite different than petroleum in that there is a potential fuels market and an existing domestic chemical methanol market supplied mostly by domestic producers. Unlike the petroleum market, however, where imports represent the marginal producer, it is anticipated that the domestic producer operating on deregulated "market" natural gas will be the marginal methanol producer. As a result, whereas subsidized petroleum synfuels displace imports, subsidized methanol production used in chemical manufacture would tend to displace domestic production. Thus, any SFC support for coal-to-methanol production must consider the market for the methanol product. Costs and benefits are quite different if the methanol is used for fuel rather than chemical applications. It is hard to develop a rationale for subsidizing large-scale production that would displace domestic chemical producers, especially as coal-based production would not compete on its own merits. As the focus is on the California market and policy alternatives, this issue need not be analyzed further, except to point out the problem and suggest that it be dealt with at the national level.

B. HIGHEST VALUED NEAR-TERM MARKETS

As part of a transition strategy, an examination has been made of a number of fuel submarkets that have been proposed as possible near-term applications and could be helpful in expanding methanol use in California. The potential applications that are particularly interesting for methanol are: repowering utility boilers, fuel for peaking turbines, dual fueling of oil-fired boilers, octane enhancer for motor fuels, blending agent for volume extention, neat methanol in retrofit car fleets, neat methanol in heavy-duty vehicles, and methanol in industrial applications. In all of these submarkets, the focus has been on the California market and to a deeper level of examination than previous methanol market assessments. The discussion below on the respective submarkets is organized into three major categories: stationary applications, synthesis, and motor fuel applications.

1. Stationary Applications

The potential for methanol use in stationary applications includes both utility and industrial uses of methanol as a boiler or peaking fuel. As a mechanism for facilitating a methanol transition in California, the

stationary applications can play an important role in bringing relatively large quantities of methanol into the state. This would create a bulk storage and distribution infrastructure. Obviously, direct substitution of methanol for oil also has both environmental and fuel diversification value and is important to the state. In this stationary applications analysis, the value of methanol and its associated market potential was evaluated, taking into account its fuel substitution value, changes in plant ratings, hardware modifications, and environmental control savings. The primary tool for this evaluation has been the SYSGEN Model,[8] described in detail in the Technical Report. It is important to recognize that the value analysis reported in this section is not a "demand" projection for methanol; rather, it is a description of the marginal value of using methanol in various types of generating units. In general, one can interpret the quantities of methanol associated with the derived marginal values as the market potential for methanol. The market potential is the maximum amount of methanol use which would result if all cost-effective uses were exploited as early as they become available. In the marketplace, there will inevitably be events that slow the response of potential adoptors and constrain the actual conversion to methanol to less than the market potential. For example, in the model there is a methanol price that makes repowering for a large class of oil-fired boilers "economic" simultaneously. In such a case, it would still be prudent for a utility to incrementally make methanol conversions to verify experimental data and get further operating experience before expanding too rapidly. The intent here is that by exposing the opportunities and problems early with more lead time, the actual market performance will move closer to exploiting the market potential, although it cannot do this competely.

Even under the most optimistic assumption that methanol becomes cost effective versus oil and natural gas in the very near term, there are technical performance and operations uncertainties that must be resolved. Thus, in order to capture a reasonable phase-in timeframe, a timetable has been developed (Figure 2-1) that shows the most likely evolution from the time methanol achieves cost-effectiveness.[9]

In this scenario, combustion turbines would be the first application because of the relative ease of conversion and the small quantities of methanol involved. The second step would bring in the Long Beach combined-cycle units because the volumes of methanol are moderate, they are supplied by water, and the capacity factors may be increased because they are now constrained by air pollution limitations. A major third step, using the experience with handling large methanol volumes and boiler firing at Long Beach, would be the conversion of the two large steam turbines suppliable by water: Ormond Beach

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[8]The SYSGEN Model dispatches the generating units optimally and calculates the system production costs of an electric generating system given detailed characteristics (fuels, costs, heat rates, availability factors, etc.) of the available generating units and the load that is to be supplied.

[9]In this context, cost-effectiveness is meant in the broad sense, including direct fuel value, modifications to equipment, rating impact, and environmental control equipment value.

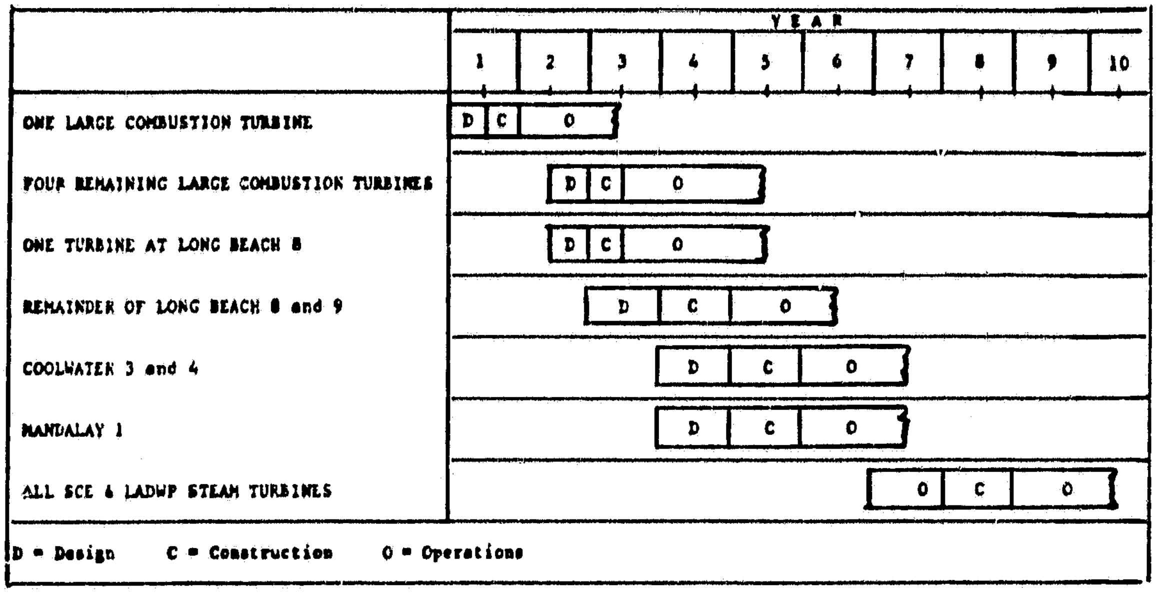

Figure 2-1. UTILITY PHASE-IN SCHEDULE

and Mandalay. Only after a successful demonstration at Long Beach would the conversion of the coolwater combined-cycle units begin, while conversion of other large steam turbines would follow a period of successful operation at Ormond Beach.

The result of expected lags in testing and implementation is that the 1987 utility potential is limited to approximately 3500 ton/day of methanol demand. In reality, it is expected to be considerably smaller because methanol will not be competitive in this timeframe under expected market conditions, thus utilities would move slowly in a testing program. As shown in Figure 2-2, methanol does not appear to be competitive by 1987 for stationary sources. Furthermore, in the case where natural gas is available to both utility and industrial customers, the margin is considerable. The only potential is where utility plants or industry are so constrained by environmental controls or regulations that they would be willing to pay a significant premium for methanol. This premium would be over $\$2.00/10^6$ Btu, and therefore is not likely to be justified except in very unusual circumstances. As an experimental program, a demand of only a few hundred tons per day might be expected if methanol is non-competitive.[10]

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[10] See Figures 9-11 and 9-12 of the Technical Report.

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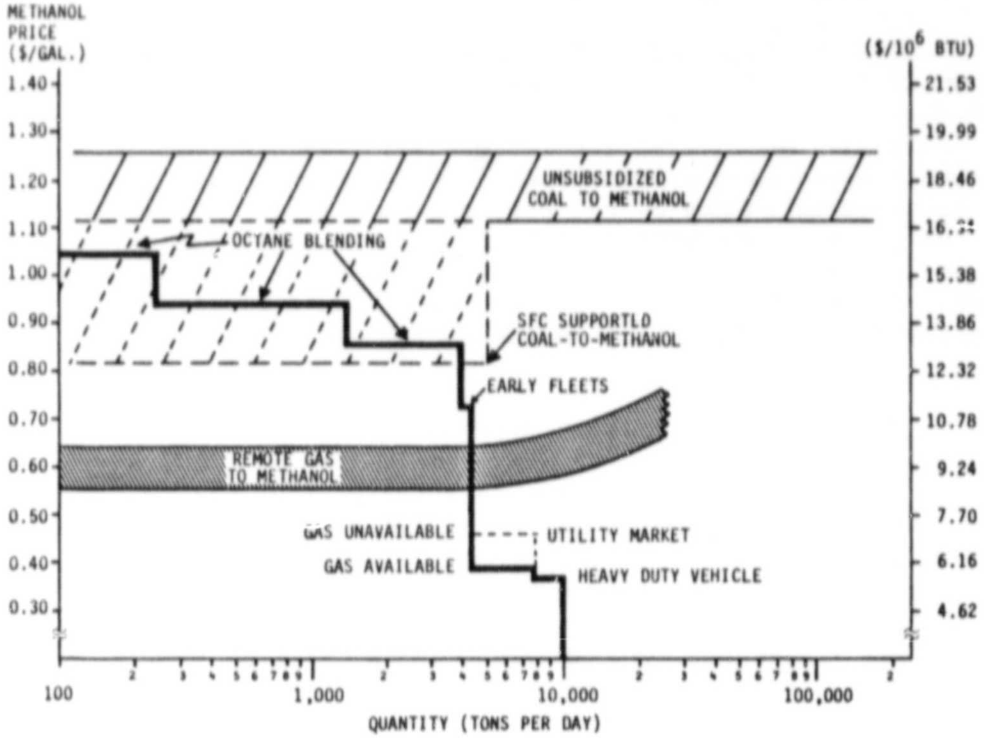

Figure 2-2. 1987 CALIFORNIA METHANOL MARKET (1981$)

2. Methanol Demand in Refining and Blending Submarkets

As discussed in Chapter 8 of the Technical Report, there are two principal applications in refining and blending. One application is the use of methanol as one of the feedstocks in the production of MTBE, and the other is use in gasoline blending for either octane or volume enhancement. There are near-term barriers to the expansion of both these submarkets. In the case of MTBE, for instance, there is no West Coast source of isobutylene, which is essential for production. The existing capacity is located with the petrochemical industry near the Gulf Coast, and it is not likely that this situation could change significantly in the near term.

The blending market in the near term (up to 1987) is most economical for the smaller (topping and hydro-skimming) refineries, where a price breakeven would occur at about $1.05/gal of methanol. A co-solvent such as TBA would have to be added in equal proportions to the methanol, and TBA is also not currently available on the West Coast. If methanol were 12 to 15 cents per gallon less expensive than on the Gulf Coast, it would compensate for TBA

transport cost and make some shipments of TBA available. Capturing this smaller application, however, would not have a significant impact on the methanol market, as it represents only 4% of California's refinery capacity and methanol would be used in only a 4.5% blend.

Thus, in the near term, the availability of TBA is the key factor in limiting blending. Other more expensive co-solvents such as propanols could be used, but this would lower the economic attractiveness of methanol blends. Larger refineries would have a lower value for methanol as an octane enhancer because they would have a lower octane number cost. Even if all the TBA currently produced in the United States were shipped to California, only about 70% of the gasoline produced in the state could be blended with methanol, which would result in slightly over 3000 ton/day of methanol demand. In the near term, it is anticipated that TBA limitation will hold this to only 300 to 500 ton/day of methanol demand in the mid-1980s.

3. Near-Term Light-Duty Fleet Vehicles

There now exists a very small methanol market in commercial fleet vehicles, supported by several small companies performing vehicle conversions to neat methanol. Even if quality methanol vehicles were available and the price of methanol fuel was such that these vehicles would have an over-the-road cost competitiveness with gasoline, the near-term potential market is probably still limited to 4000-10,000 vehicle sales per year. This is due to constraining factors such as uncertainty of resale value, ready availability of methanol fuel, and customary maximum trip lengths for the vehicles. If methanol vehicles were in fact sold at this volume, it would imply an increase in methanol demand of between about 20 and 75 ton/day. Such a volume is quite small in comparison to a remote natural gas methanol plant size of 2000-4000 ton/day.

C. NEAR-TERM SUMMARY

As shown in Figure 2-2, the most likely outcome in the near term is for very limited quantities of methanol being consumed within the state. The maximum competitive market size would be approximately 4000 ton/day if 3-1/2% blends of California gasoline were made. A more likely outcome is that demand will be approximately 1000 ton/day, with perhaps 800 ton/day to blending markets, 100 ton/day to vehicle fleets, and 100-200 ton/day utilized for utility experimentation. The only way that this outcome could be significantly affected would be for the West Coast TBA capacity to be expanded or the regulatory climate in California to be eased to facilitate blending with higher allowed Reid Vapor Pressure.

On the supply side, the likely sources for methanol during this period through 1987 would be from installation already under construction and based on natural gas feedstocks. The excess supply for chemical uses could total nearly 10^9 gal/year by 1987. In spite of this large excess capacity, however, a drop in price to below $0.60/gal delivered to California is not anticipated because U.S. producers will have variable costs above this level, which would imply shutting down at lower prices. Thus, marginal production

costs will tend toward the U.S. marginal producer using market gas as feedstocks. Prices are not likely to fall sufficiently to make methanol competitive with natural gas for stationary applications or with diesel fuel for trucks and buses.

SECTION III

THE COMPETITIVE ENVIRONMENT

A. FUELS OVERVIEW

The following section describes in detail the present and projected competitive environment for methanol in California, with emphasis on two key issues: (1) the availability and price of natural gas and residual oil to California utilities and (2) the likely range of cost for motor fuels in California.

The poor record of energy forecasters over the past decade clearly illustrates the difficulty of making long-term projections in a rapidly changing political and economic environment. In Figure 3-1, forecasts of primary energy consumptions in the United States are shown for the period 1980-2000. These forecasts were made in 5 different years using a consistent forecasting model.[11]

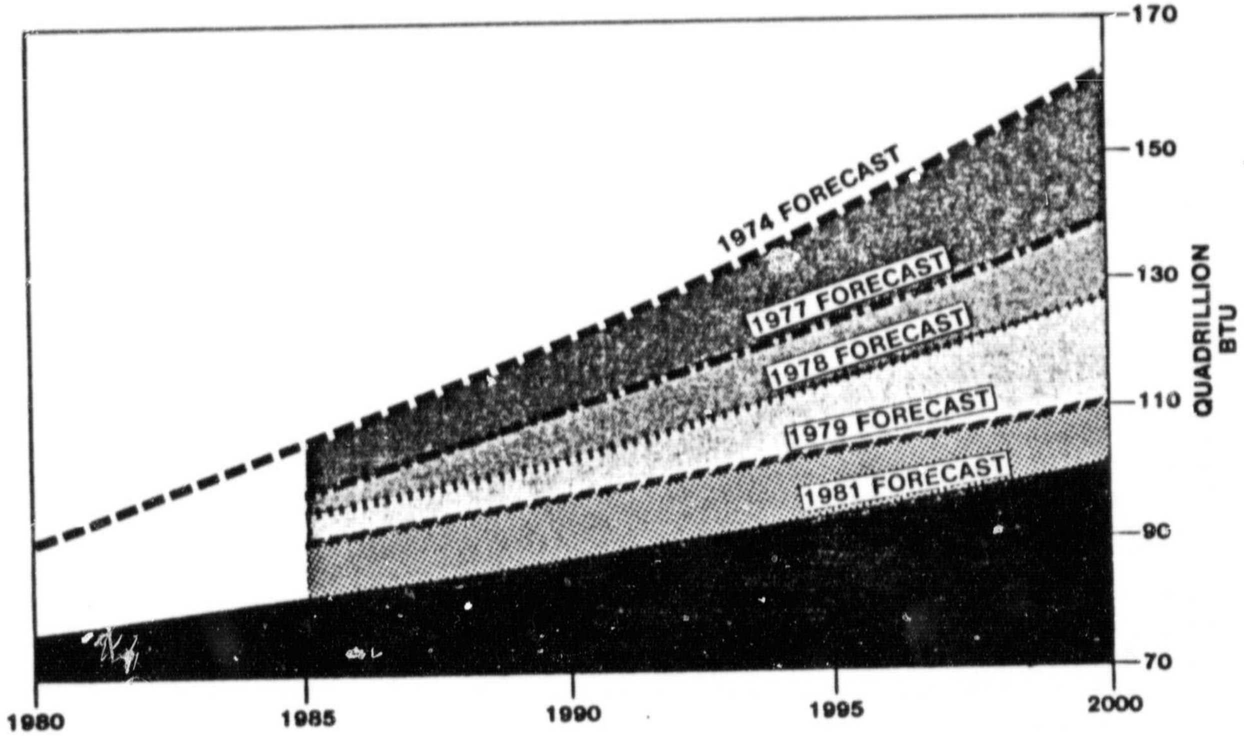

Figure 3-1. FORECASTS OF TOTAL PRIMARY ENERGY CONSUMPTION IN THE UNITED STATES

[11]The Data Resources, Inc. forecasting model.

The cumulative impact of the revisions in the year-2000 forecast are substantial, dropping nearly 40% from 1974 to 1981. These changes are a result of political factors (Iran-Iraq War) as well as economic ones (larger demand elasticities than expected), and as a result the level of understanding of the forces that affect U.S. energy consumption is improving. It is still very difficult, however, to accurately predict the quantities of different energy sources consumed in the year 2000. The major value of large forecasting models is to show the impact of specific events or sensitivities in relation to some base case, not to forecast long-term magnitudes.

In California, the dependence on oil and gas will probably be higher than for the nation as a whole. In electricity generation within California, for instance, approximately 8% to 9% of utility fuel demand will be for oil and 20% for natural gas, which is significantly above the national average. In transportation also, California will exceed the national average in use of motor fuels per capita, but here the difference from the average is less extreme.

Fortunately, it is not critical for purposes of this report to make precise forecasts of liquid fuel and natural gas consumption levels. Rather, it is more important to define the expected climate for the fuel market in the 1987-1997 time period. At this general level, the findings are fairly clear cut. For the United States as a whole, domestic sources, including synthetic liquid fuels, will be insufficient to supply expected demands, and thus oil imports will probably represent 30% to 40% of the U.S. oil supply. The bulk of this oil will be used for transportation, but there will still be some oil burned in electricity generation (2% to 3% of utility fuel demand). Also, on the national level it is expected that natural gas will represent 5% to 6% of utility fuel demand.

The key questions about the use of natural gas in California are: (1) What price will it sell for after decontrol? and (2) Will there be sufficient quantities to supply low priority users in California? In the Natural Gas Policy Act of 1978, a complex pricing scheme was created which was designed to bring the price of most new gas to a decontrolled market level by 1985. There would, however, be price controls indefinitely on certain classes of flowing gas. A problem arose with this policy almost immediately after it was enacted because of the major price increase of imported oil in 1979. Because new gas was escalated at the inflation rate, gas prices lagged far behind the increase in oil prices. There was much concern in the Federal Government that, accompanying decontrol in 1985, there would be a very rapid rise in decontrolled gas. With the decline in the real price of oil in 1982, the "fly-up" problem and concern over it has dissipated. There will still be a significant price increase in 1985, when about 65% of all natural gas supplies are decontrolled, but it should be politically acceptable.

The market clearing price of natural gas in 1985 will clearly depend on oil prices in that timeframe. Under the baseline scenario of virtually constant real oil prices in the period 1982-1985, it is likely that natural gas prices will tend toward parity with the price of residual oil to end users.

1. California Electric Utility Fuels

In California, where only low sulfur oil (0.25-0.50% sulfur) can be used due to environmental constraints, natural gas should tend toward parity with its value to the marginal user, which would be the price of 0.5% sulfur oil in industrial boilers. In an unregulated market, therefore, electric utilities (required to use 0.25% sulfur oil) might be able to acquire gas at a slight bargain over their alternative fuel price. It is possible, however, that the Public Utilities Commission (PUC) will pass along the higher costs of gas to these users up to the point of fuel switching, which is at parity with 0.25% sulfur residual oil. The difference between these alternatives is not that significant (approximately 5%) given the overall uncertainty in the market forecast anyway. Thus, for the Southern California area, the price of 0.5% sulfur oil was used for electric utilities. For natural gas prices, the premise was adopted that the market value will tend toward the price of 0.5% sulfur oil as the alternative price of the marginal user. It should be noted, however, that natural gas could have a value about 5% higher if PUC passes the higher costs (up to parity with 0.25% sulfur oil) along to the electric utilities. Table 3-1, derived from the Data Research, Inc. (DRI) Spring 1982 Energy Review, summarizes the utility fuels cost situation. Forecasts made by DRI have been used throughout this report to provide a consistent frame of reference. It should be noted that Table 3-1 represents the average acquisition cost of gas to all utilities. It is expected that electric utilities will pay a higher price in 1982 to 1985 equal to the cost of residual oil at the point of use.

California's electric utilities pay higher fuel prices as a result of requirements for lower sulfur fuels and longer transport distances. For example, the U.S. price to all utilities for residual oil is forecasted by DRI to be $\$5.95/10^6$ Btu and $\$7.73/10^6$ Btu in 1990 and 2000, respectively. In the base case forecast, shown in Table 3-1, there would be sufficient natural gas for the market to supply about 2.0 quads to California, which is about the quantity consumed in 1982, although less than what may be supplied in the

Table 3-1. BASE CASE CALIFORNIA UTILITY FUEL COSTS (1981$\$/10^6$ Btu)

	1981	1982	1983	1984	1985	1990	1995	2000
COAL	1.89	1.96	2.04	2.18	2.21	2.76	3.27	3.74
NATURAL GAS[a]	3.93	4.10	4.39	4.83	5.01	6.37	7.44	8.06
RESIDUAL OIL								
0.50% sulfur	5.80	5.44	5.42	5.41	5.49	6.68	7.58	8.18
0.25% sulfur	6.67	5.77	5.68	5.67	5.76	7.00	7.95	8.58
DISTILLATE OIL	7.17	6.15	5.90	5.95	6.12	7.89	9.37	10.60

[a]Natural gas prices in this table are the acquisition prices for all utilities. It is expected that electric utilities will pay prices based on the cost of residual oil in their service area.

intervening years. The implication of this forecast is that California industry and electric utilities will probably benefit from the deregulation of natural gas prices. Price increases will increase conservation in residential markets, while parity in price with mid-sulfur residual oil prices will induce some industrial consumers across the nation to use oil instead of gas. On the production side, higher prices will induce some sources of supply which would otherwise not be economic, although a major supply response is not expected. In fact, by the year 2000, natural gas consumption is expected to decline from approximately 20 quads per year in the period 1980 to 1990 to about 18.5 quads in 2000. Over this period, lower 48 states production should decrease from over 19 quads per year to below 14 quads per year. The remainder will be supplied by supplemental sources (Alaskan North Slope, Canadian imports, Mexican imports, LNG and SNG).

The issue of natural gas availability to California industry and electric utilities is more uncertain than its price relationship to oil. Two current and pertinent sources were used for this subject: DRI's own projection on availability and the 1982 California Gas Report, prepared by the Utility Industry Committee. The projections of each are shown in Table 3-2 for 1982 through 2000.

Table 3-2. NATURAL GAS AVAILABILITY (Trillion Btu)

	1982	1983	1984	1985	1990	1995	2000
DRI[a]							
Gas Available	2004	1972	2007	2096	2265	2078	1968
Non-Utility Gas Demand	1146	1161	1235	1300	1293	1254	1206
Electric Utility Demand							
Gas	713	662	618	638	793	625	541
Oil	311	289	285	277	345	254	219
Percentage Available							
Gas	100	100	100	100	100	100	100
Gas and Oil	84	85	85	87	85	94	100
1982 California Gas Report[b]							
Gas Available	2191	2202	2091	2013	2031	1964	1917
Non-Utility Gas Demand	1238	1242	1271	1296	1360	1449	1537
Electric Utility Gas Demand	762	619	512	499	435	457	435
Percentage Gas Available	85	94	95	87	83	71	51

[a]Data Resources, Inc., Energy Review, Vol. 6, No. 2, Summer 1982.

[b]1982 California Gas Report, prepared by Utility Industry Committee, 1982.

An examination of Table 3-1 shows that both sources are quite consistent in their estimates of gas available to California markets; where they differ is in the projected demand by residential gas customers. DRI predicts greater conservation in this sector (in spite of a 1.4% annual growth in housing units heated by gas) than does the 1982 Gas Report. As a result, there is more gas remaining for the electric utility sector according to DRI.

Although it is likely that a large proportion of gas demand by electric utilities can be satisfied through at least 1990, there is no basis in either of these studies for concluding that 100% of both oil and gas needs can be supplied by natural gas over this entire period. Thus, in the utility analysis of methanol demand, both the gas-available case for all oil and gas units and the no gas-available case for these same units were considered. It is much more likely, of course, that actual experience will fall between these two extremes, and there does appear to be a strong conviction that all the demands of higher priority users (residential, commercial, industrial) can be supplied over the forecast period. As the lowest priority market, therefore, electric utilities must make contingency plans for a range of outcomes which permit them to take advantage of available natural gas; this fuel should be in sufficient supply to meet most if not all of these demands in the near term (through 1990), but is more uncertain in the long term. Long-run residential and industrial conservation as well as supplemental gas supplies will ultimately affect availability.

Higher oil prices under some sustained disruption scenario would tend to strengthen the conclusion that natural gas will be available to California utilities at market clearing prices. In this case, the higher oil price levels will lead to higher gas prices, which combine to induce further conservation and reduction in real economic growth, thus leaving the consumption of natural gas lower than the base case.

California has special problems with air pollution which make the use of natural gas in utility and industrial applications important to achieving air quality goals. Artificial constraints on gas use in these stationary applications are, therefore, not in the state's interest. In the absence of regulatory constraints that force a reduction in natural gas use, the California utilities should be able to satisfy a substantial proportion of their demands throughout the 1982-1995 time period.

2. Transportation Fuels

Liquid fuel use in California in the 1985-1990 timeframe and beyond will be dominated by the transportation market, as shown in Table 3-3. In 1980, about 65% of the liquid fuel consumed in California was burned in cars, trucks, trains and airplanes, and most of the remainder was burned in electric utilities. Of the liquid fuel consumed in transportation, almost 90% was used for vehicles.

A number of factors will determine future liquid fuel use for transportation in California, including: the mandated improvements in fleet miles per gallon of passenger cars, the economic health of business, the projections being made that trucks will gradually increase their present share of the

Table 3-3. MOTOR FUEL USE IN CALIFORNIA (10^6 gal/year)

	1980	1985	1990	1995	2000
GASOLINE	11,108	9,840	8,800	8,640	8,400
DIESEL FUEL	1,803	2,163	2,524	2,668	2,884
TOTAL	12,911	12,003	11,384	11,308	11,284

transportation liquid fuel market, and gradual displacement of gasoline-powered cars by diesels. Several of these factors act in opposing directions. The varied nature of these liquid fuel-use factors, coupled with the uncertain future of the economy, makes it difficult to predict future fuel consumption accurately. Of course, a major supply disruption could also affect the picture.

It appears that there will be a decrease in consumption of gasoline by cars between 1980 and 1990, but an increase in diesel fuel consumption. Liquid fuel consumption by trucks will probably rise. The net result may be a modest decrease in liquid fuels consumption by the transportation sector.

The net effect of all these changes is a projection for a modest decrease in consumption of motor fuels of less than 1% annually from 1980 to 2000. Gasoline use falls off 25%, but is still about three-fourths of total motor fuel use by the turn of the century. In the base case forecast, the projected prices of motor fuels are summarized in Table 3-4 consistent with the user demands in Table 3-3.

This motor fuel price forecast incorporates the assumption of weak markets, where 1982 real prices hold through 1985 and then begin rising at about 2% per year in real terms. The price of distillate fuel is also predicted to rise relative to gasoline as an increasing proportion of diesel vehicles and demand for diesel fuel drives up the relative price. Table 3-3 was used as the baseline forecast for the analysis of methanol use in vehicles, but higher and lower price scenarios were also considered for purposes of sensitivity analysis.

Table 3-4. MOTOR FUEL PRICES (1981$/gal)

	1980	1985	1990	1995	2000
GASOLINE	1.35	1.23	1.53	1.74	1.88
DIESEL FUEL	1.13	1.11	1.42	1.69	1.85

B. NEED FOR SYNTHETIC LIQUIDS

Two types of benefits are potentially associated with significant synthetics capacity. First, if the supply of synthetic fuel is significant, it will affect the world price of oil, not only saving the producing country the bill for the displaced oil, but also lowering the price of the remaining imported oil. This effect of a synthetics program has been termed the "market power" impact by the Energy Modeling Forum.[12]

The second benefit of synthetic fuel capacity in place when a disruption occurs is the reduced economic impact that ensues resulting from less dependence on foreign sources, called the security effect.

During the late 1970s, California produced only about one-third of the petroleum that it consumed. This was part of a long-term pattern in which annual consumption has outgrown annual discoveries and proven reserves have declined. The known recoverable reserves amount to about 5 billion barrels, and these are being drawn down at the rate of about 0.4 billion barrels per year for a lifetime of about 13 years. Future discoveries (such as the recent offshore discoveries), extensions, revisions, and improvements in extraction will probably add another decade to this supply. Nevertheless, California's capability to supply even one-third of its consumption is of limited duration.

On the national scene, the petroleum outlook is far better than it was 2 years ago, but not encouraging to those who expect further disruptions in imported oil. It is clear that domestic conventional supplies will continue to decrease over the remainder of this century. Large increases in tertiary recovery (to 1 MMBD[13] by the year 2000) and small increases in the use of heavy oil will help somewhat, but the total of these conventional sources, including Alaska, will likely decrease with time, as shown in Table 3-5.

Table 3-5. U.S. DOMESTIC OIL SOURCES (MMBD)

	1982	1985	1990	1995	2000
DOMESTIC SUPPLIES					
Conventional	6.3	5.8	5.5	5.1	4.7
Tertiary	0.1	0.4	0.5	0.7	1.0
Heavy Oil	0.6	0.7	0.8	0.8	0.8
Alaskan	1.6	1.6	1.6	1.5	1.5
SUBTOTAL	8.6	8.5	8.4	8.1	8.0
SYNTHETICS					
Coal Liquids	0.0	0.0	0.0	0.05	0.15
Shale	0.0	0.1	0.03	0.05	0.25
NET IMPORTS	4.4	4.8	5.1	5.1	5.6
TOTAL	13.0	13.6	13.5	13.3	14.0

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[12]Energy Modeling Forum, World Oil, EMF Report 6, February 1982.
[13]Million barrels per day (MMBD).

Synthetic oil from shale and coal is not expected to add significantly to domestic production, totaling between a quarter- and a half-million barrels per day by the year 2000. The synthetics industry is in a state of declining expectations following the cancellation of the proposed Colony project[14] after construction cost estimates rose from $3 billion to $5 billion. If one assumes that imports are the marginal source of supply, it is clear that there will still be a substantial quantity of imported petroleum by the year 2000. A reasonable estimate at this point would be approximately 5 MMBD net imports through the mid 1990s and then increasing to about 5.5 MMBD by 2000. The precise numbers are really not crucial for this analysis because the levels of imports are so large relative to synthetic fuels supply in that time period. Imported petroleum prices define the marginal cost of oil and thus the target for alternatives such as methanol.

In addition to the U.S. level of imports, another measure of our vulnerability to oil disruption is the proportion of world oil supplied to the market by the Middle East. This area's political instability is the source of most of the concern over our import level, thus their influence is more critical as their share of the oil supply increases. In Table 3-6, the production levels for OPEC are shown for the recent past and and projected to 1990. Although OPEC is expected to supply a decreasing proportion of world oil over the remainder of this decade, they will remain a major force in international oil markets. Thus, although the United States is importing less petroleum, the world as a whole will remain dependent on OPEC for about 40% of world supply. As a result, there is a strategic need for synthetics, although there is certainly sufficient world oil to meet U.S. and California demands under the base case and alternative price scenarios discussed in the following section.

Table 3-6. WORLD OIL BALANCE

	1980	1982	1985	1990
WORLD DEMAND				
Western Industrialized	30.8	27.6	28.4	29.2
Other Developed	6.8	6.7	6.9	7.1
Non-OPEC LDCs	8.3	8.4	9.6	11.5
OPEC	2.7	3.1	4.0	6.0
Communist Bloc	13.8	13.6	15.1	16.7
WORLD SUPPLY				
Free World/Non-OPEC	21.3	25.4	24.9	26.6
Communist Bloc	14.2	14.4	14.9	15.8
OPEC	26.9	19.6	24.2	28.1

[14]A joint venture for the development of shale oil by Exxon and Tosco.

The need for synthetic liquid fuels can be viewed from intermediate and longer-term viewpoints. From an intermediate-term strategic point of view, continued heavy dependence on foreign oil through the 1990s makes the United States vulnerable politically and militarily. From a longer-term point of view, it is clear that the United States is fighting a losing battle in trying to maintain its present production rate of petroleum. As the twentieth century winds down, the United States will have to produce synthetic liquid fuels, import more oil, conserve more vigorously, or pursue some combination of all three options. While it might be possible to get through the 1980s and 1990s without any substantial production of synthetic liquid fuels, the following decade will require some synthetics. The only way to build a synthetics market in the 2000s is to begin a transition in the 1990s.

C. ALTERNATIVE PRICE SCENARIOS

1. Base Case Scenario

Given the major uncertainties that exist in energy markets, it is prudent to consider alternative oil and natural gas price paths as the basis for methanol competition in the transition period. The major elements of the base case scenario are contained in Sections 3.A.1 and 3.A.2, but there are also reasonable sets of events which could make energy prices diverge significantly from the base case. The base case assumptions are discussed in DRI's Spring 1982 Energy Review[15] and are not discussed in detail here. A set of alternative assumptions has been established which are fed into their energy forecasting model; these are referred to as the PESSIMCRUDE and OPTIMCRUDE scenarios. The key features of these scenarios are shown in Table 3-7.

Probabilities are placed by DRI at no more than 10% in the pessimistic case and 5% in the optimistic case. Clearly, these scenarios depend very strongly on behavior in the Middle East and, although it can be expected that disruptions will certainly occur, it is unlikely that they will be sustained consistently over the forecast period. Deciding the appropriate weights to place on the alternative scenarios is a subjective process. All three cases were used in the study for evaluation of methanol and other synthetics simply because there is so much uncertainty over the entire analysis period. As a summary of the price forecast implications, the three energy price scenarios are shown in Table 3-8.

A few features of these scenarios and their price implications are particularly interesting for this study. First, the range is quite wide in the longer term. Whereas the base case for imported oil in 1985 is $32.50/bbl with a range of from $23/bbl to $39/bbl, this range expands by the year 2000 from $31/bbl in the optimistic case to about $81/bbl in the pessimistic scenario. Although one might take issue with these precise values and the probabilities which DRI associates with them, it was concluded by this study that the range is realistically wide in the long term. Through 1985, the risks are somewhat reduced by the excess capacity in OPEC, which really implies that only a threat to Saudi Arabia could significantly affect the world oil price.

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[15]Data Resources, Inc., Energy Review, Vol. 6, No. 1, Spring 1982.

Table 3-7. ALTERNATIVE ENERGY SCENARIOS

<u>PESSIMISTIC CASE</u>

- Lower long-term elasticities than current best estimates.
- More pessimistic view of world oil resource base than current best estimates.
- The Middle East moving from one moderate supply disruption to the next with virtually no respite for 1982 through 2000.

<u>OPTIMISTIC CASE</u>

- Long-term elasticities of demand for oil turn out to be higher than current best estimates.
- New discoveries of oil fields and gas resources are higher than current best <u>estimates</u>.
- The Middle East experiences no <u>net</u> oil disruption over the next 18 years.

Data Resources, Inc., <u>Energy Review</u>, Vol. 6, No. 2, pp. 111-113, Summer 1982.

After 1985 the increased demands within OPEC for oil and a presumed recovery in the industrialized world will tend to reduce this excess capacity. Thus, the possible threats increase for oil distruptions because in a tighter market with Saudi Arabia operating nearer full capacity, even the loss of a relatively small producer resulting from political turmoil could start prices escalating. The pessimistic scenario to which DRI gives a 10% probability is unlikely to occur because it requires sustained disruptions of medium scale (e.g., such as those induced by the Iran-Iraq War) in combination with low long-run demand elasticities and a low rate of oil field discovery. It must be recalled, however, that these are not mutually exclusive scenarios. If any one of the premises in Table 3-7 is valid for the pessimistic scenario, it will drive prices higher than the base case. A price path in the range between the base case and pessimistic scenario is quite possible, although prices at the extreme-end pessimistic case level are unlikely.

Since the DRI forecast in the spring of 1982, the prospects for the lower or optimistic scenario have improved. More recent forecasts by DRI and others (see Figure 3-2, p. 3-12) indicate that a scenario below the base case is

Table 3-8. ALTERNATIVE ENERGY PRICE SCENARIOS (1981$)

	OPTIMISTIC CASE	BASE CASE	PESSIMISTIC CASE
TOTAL ENERGY DEMAND 2000 (quad)	103	95	90
DOMESTIC PRODUCTION OF CRUDE AND NATURAL GAS LIQUIDS 2000 (MMBD)	8.65	9.15	9.8
ENERGY PRICES			
Imported Oil			
1982	30.22	32.49	33.95
1985	22.84	32.58	39.26
1990	24.96	41.56	52.77
1995	28.31	49.59	68.07
2000	30.67	55.90	80.94
REFINER ACQUISITION OIL COST($/bbl)			
1985	22.11	31.54	38.00
1990	24.49	40.77	51.77
1995	27.89	48.85	67.05
2000	30.36	55.34	80.13
CALIFORNIA UTILITY NATURAL GAS ($/10^6 Btu)[a]			
1985	3.80	5.01	5.10
1990	4.16	6.37	6.73
1995	4.71	7.14	8.68
2000	5.11	8.06	10.32
CALIFORNIA UTILITY RESIDUAL OIL ($/10^6 Btu)[b]			
1985	3.34(3.50)	5.49(5.76)	5.74(6.02)
1990	3.65(3.83)	6.68(7.00)	7.72(8.09)
1995	4.14(4.34)	7.58(7.95)	9.96(10.44)
2000	4.49(4.71)	8.18(8.58)	11.84(12.42)

[a]Natural gas prices are for the general case and would be higher in electric utility areas where 0.25% sulfur residual oil is required.

[b]For residual oil prices, two values are given for each case: the first represents the price forecast for mid-sulfur residual oil (0.50% to 0.75% sulfur), while the price in parentheses is for low-sulfur residual oil (0.25% sulfur), which is appropriate for some parts of California.

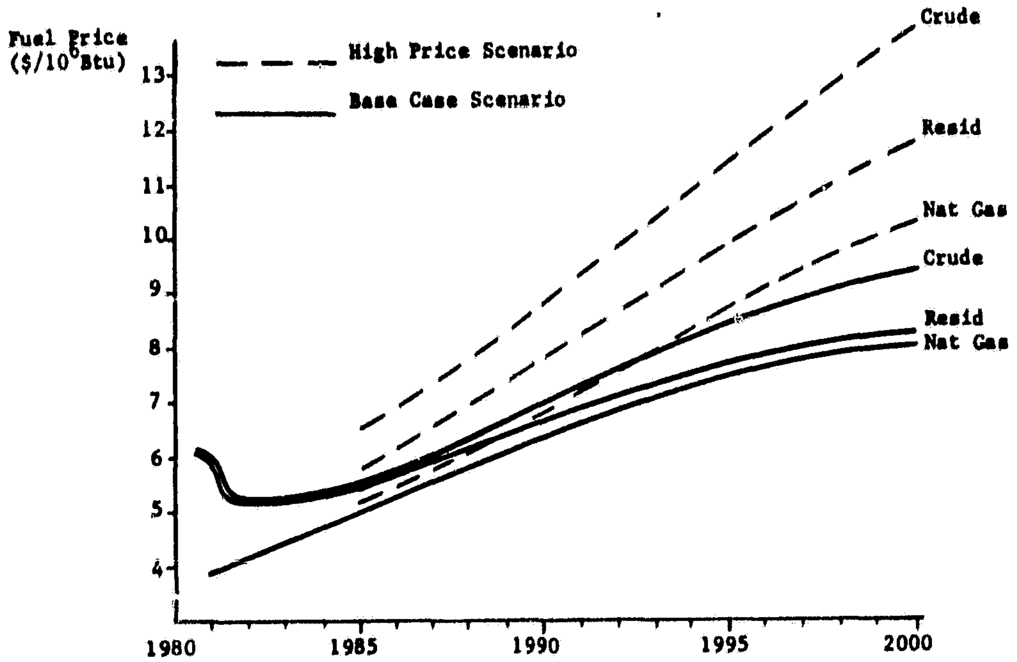

Figure 3-2. ALTERNATIVE FUEL PRICE FORECASTS (1981$)

increasingly likely. These scenarios show the impact of politics on the world oil market. If the market could simply operate without the influence of political turmoil, this case would seem a very real possibility. With potential OPEC capacity of at least 30 MMBD and current output at only 19 MMBD there would certainly be room for expansion to supply world demands, even with economic growth in the industrial world. Thus, with all factors considered, the base case scenario still appears realistic, but the existence of a credible, wide range will discourage capital investments that would be unprofitable if the optimistic case or even something below the base case materializes.

A second factor which is interesting about the energy scenarios is that natural gas prices are not likely to vary as widely as oil prices in the extreme scenarios. In the optimistic scenario, for instance, lower oil prices lead to somewhat stronger economic growth in the United States (approximately 0.4% difference, according to DRI). At the same time, the lower oil and gas prices result in less production, as the profit incentive is lower than in the base case. The impact of lower oil and gas prices leads to a stimulation of demand in the residential and commercial sectors that is disproportionately higher for gas due to less conservation and higher income effects. The lower

priority users (industry and utilities) will face some reduced availability as a result. In order to attract sufficient gas to meet demands by these lower priority users, the price of gas will tend to rise versus oil. Whereas in the base case the equilibrium price of gas is at the mid-sulfur (0.75%) level, it will tend toward parity with low-sulfur oil (0.25%) in the optimistic scenario according to DRI.

In the pessimistic scenario the reverse impacts tend to occur. As oil and gas prices rise, real growth is reduced, which induces greater gas production and reduced demand among high priority users (residential and commercial). Low priority users (industry and utilities) will thus experience a relatively higher availability of natural gas compared to oil, which drives down the relative price. As a result, in the pessimistic case, natural gas would tend to achieve price equilibrium at the high-sulfur residual oil price.[16]

As a result of these considerations, the general conclusion is that natural gas will achieve parity with the residual oil price after deregulation, but that it will have less variance than oil prices under the alternative energy price scenarios. According to the DRI forecast, the range for oil prices is from 55% of the base case for the optimistic scenario to 145% of the base case for the pessimistic scenario in the year 2000. For natural gas prices, on the other hand, the range is from 63% to 128% of the base case forecast for the optimistic and pessimistic scenarios, respectively. The implications of this are that the impact of the alternative energy price scenarios will be much more significant on transportation markets in California than on utility markets, where natural gas is used. Furthermore, the high price scenario reinforces the likelihood of natural gas being available to low priority users so that if synthetic fuels are non-competitive at the high price or pessimistic scenario, the prospects are further reinforced by the increased availability of gas in this case.

2. Severe Oil Disruption

The prospect of a severe oil disruption caused, for instance, by partial or total destruction of Saudi Arabian production capacity has been cited as a reason for the need for synthetic fuels. The policy implications of this issue are discussed in Section VII of this report, but the event is briefly discussed here as a possible energy scenario. Perhaps the most important point is that the role of synthetics in reducing the impact of a severe oil disruption is a question of timing. Once a disruption begins it is already too late to turn to synthetic fuel production as a solution. The lead times on such projects are so long (8 years or more from start of planning to commercial operation) that their impacts would be too delayed to help.

There are many potential benefits from reducing dependence on foreign oil through the use of synthetic fuels (see Section VII for estimates of this value), but the key is that the capacity must be in place or close to

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[16]Data Resources, Inc., Energy Review, Vol. 6 No. 2, pp. 125-128, Summer 1982.

completion when the disruption occurs. It is doubtful a single severe disruption would be a triggering mechanism for a methanol transition. Such a transition must begin in anticipation of this type of event in order to pay signficant dividends. A premium on imported oil has been discussed as a possible policy mechanism to create incentives for an earlier movement to synthetics, along with the existing program of loan and price guarantees provided by the Synthetic Fuels Corporation.

In summary, it is believed that the base case pessimistic price scenario captures the pertinent aspects of a disruption scenario over the long term from a market viewpoint. The social and policy issues are discussed in Section VII of this summary.

D. COMPETITIVE ENVIRONMENT OVERVIEW

To summarize the competitive environment for methanol, alternative price scenarios for crude oil are compiled into Figure 3-2 (see p. 3-12). The figure illustrates how the increasing uncertainty further into the future makes choices on capital-intensive projects very difficult. The baseline, high price, and low price scenarios are all from DRI's Spring 1982 Energy Review. In their Fall 1982 Energy Review, DRI lowered its baseline forecast. The baseline forecasts from two other sources (DOE's Office of Policy Planning and Analysis and Chevron) provide some perspective on how others view the price forecasts. Although not shown in the figure, the high and low scenarios for both Chevron and DOE are within the extremes of the DRI scenarios. Thus, the range of forecasts from DRI that have been used within the study encompass the projections of other knowledgeable energy market analysts.

A more comprehensive summary of the entire set of factors affecting the competitive environment in California is provided in Table 3-9 for the Pacific-2 region[17] in DRI's forecasting system. This table shows demands for energy, fuel prices expected, and the economic conditions that drive the results for the base case forecast.

As was discussed above, the precise values of the forecast prices and quantities are not as important as the general climate for synthetic fuels in the transition period of 1982 through 2000. The key factors during this period are:

(1) The United States and California will remain dependent on imported oil.

(2) Natural gas after deregulation will tend toward parity with residual oil. For electric utility purchases of natural gas, parity pricing has already occurred.

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[17] In DRI's system, Pacific-2 includes Hawaii as well as California; however, in fuel markets, California dominates by such a substantial margin that this does not significantly affect the conclusions made.

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Table 3-9. BASE CASE FUEL FORECAST SUMMARY FOR CALIFORNIA (quad/year)

	1980	1985	1990	1995	2000
VEHICLES					
Gasoline	1.44	1.23	1.10	1.08	1.05
Distillate	0.25	0.30	0.35	0.37	0.40
SUBTOTAL	1.69	1.53	1.45	1.47	1.45
ELECTRIC UTILITIES					
Natural Gas	0.52	0.59	0.54	0.49	0.45
Oil	0.48	0.36	0.49	0.37	0.13
SUBTOTAL	1.00	0.95	1.03	0.86	0.58
INDUSTRY					
Natural Gas	0.54	0.36	0.39	0.39	0.37
Distillate Oil	0.05	0.05	0.04	0.04	0.03
Residual Oil	0.04	0.04	0.03	0.03	0.03
SUBTOTAL	0.63	0.45	0.46	0.46	0.43
PRICES (1981\$/10^6 Btu)					
Gasoline	10.66	9.85	12.42	14.39	15.97
Residual Oil (0.5% sulfur)	5.47	5.49	6.68	7.58	8.18
Distillate Oil	6.30	6.12	7.89	9.37	10.60
Natural Gas: Utilities	3.84	5.01	6.37	7.44	8.06
Natural Gas: Industrial	3.97	5.07	6.41	7.47	8.09

(3) The contribution of synthetic fuels nationally will probably be less than 500,000 bbl per day by the year 2000.

(4) Although there is sufficient oil worldwide and unused capacity in OPEC to supply anticipated demands in the transition period at real escalation rates of 2% annually or less, political disruptions could drive prices up much faster.

(5) There is a plausible wide range of oil price scenarios in the 1990s which work against those large-scale capital projects that must rely on high price scenarios for viability.

(6) The real price decrease since the peak 1981 oil price level has severely impacted the enthusiasm for synthetic fuels and will probably negatively impact such projects even if another sudden price rise occurs (it is much more obvious now compared to 1981 that oil prices can fall rapidly in response to demand reductions and OPEC's failure to cut output sufficiently to defend target prices).

SECTION IV

LONG-TERM METHANOL MARKET

A. INTRODUCTION

In order to sensibly evaluate alternative transition paths, it is necessary to have some perspective of the long-term goals toward which the transition is aimed. The intent of this section is to describe the long-run methanol supply and end-use system after the early transition is complete and methanol has established itself as a viable fuel. This description cuts across the chapters in the Technical Report by summarizing the likely production technologies, competitive environment, transport mechanisms, end-use markets, utilization technologies, and environmental consequences. Following a description of this end-to-end methanol system, some conjectures are offered on the minimum timeframe within which such a system could be established.

No implication is made here, however, that this long-run system is inevitable or even desirable at this point in time. Too many intermediate steps must be successfully completed before such a determination is made. The input of technology advances in gasification, direct liquefaction, and shale extraction and processing are impossible to judge accurately now, and it is not known which energy price scenario will occur or how successful efficiency improvements in vehicles will be in the long run. Consequently, to forecast the ultimate role for methanol and when it will occur is unproductive. What can be done is to describe what the long-run system would look like if the intermediate steps are successful. Therefore, the goal of this section is to discuss whether the long-run outcome provides potential worth to an attempt to accelerate the transition period.

B. LONG-RUN PRODUCTION FEEDSTOCKS AND TECHNOLOGY

In the period 1997-2000, if the preconditions on methanol development have been successfully achieved, there are really only two potential feedstock sources for methanol: western coal and Alaskan North Slope natural gas. Both of these feedstocks exist in sufficient quantities to supply an established and growing methanol fuel demand, and have further strategic value as domestic sources which are not subject to Middle Eastern political and social instability.

1. Coal to Methanol

The case for western coal is fairly well established. There are over two trillion tons of western coal, much of it subbituminous coal well suited to methanol conversion. Within the Green River and Powder River coal regions[18] there are nearly 1300 billion tons of total reserves with approximately 275 billion tons under less than 2000 feet of overburden. The sulfur

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[18] See Table 3-4 of the Technical Report.

content of these coals varies significantly from about 0.35% to over 5%, and the Btu content varies from just under 8000 Btu/lb to over 12,000 Btu/lb. Other fields which could become the center for western methanol supply are the Black Mesa and San Juan coal regions. The point is that the feedstock resource is not the constraining factor in the long-run methanol market. Ample coal exists in western fields that could be used without driving up resource prices 1% per year beyond general inflation rates. In other words, the coal supply is elastic enough to supply a significant quantity (e.g., 25%) of U.S. fuel needs through coal-to-methanol conversion.

From an evolutionary sense, one of the interesting factors will be how cost reduction takes place through (1) economies of scale in production, (2) economies in transportation, and (3) risk reduction in technology and markets. Table 4-1 shows how coal-to-methanol production costs potentially could vary with alternative scale economies of production and transportation and lower costs of capital associated with risk reduction. It must be stressed that all these factors relate equally well to other synfuels such as shale oil, direct liquefaction, and coal gasification. Thus, these long-term potential improvements in methanol economics do not necessarily improve its relative competitiveness to these fuels, but could help to make methanol more competitive over conventional fuels such as gasoline, which already benefits from some of these factors. The effect of production scaling on capital cost is illustrated by the impact of a 0.85 scaling factor on increased plant size in moving from 5000 ton/day to 21,000 ton/day in coal-to-methanol plants. Capital cost on a per gallon basis would decrease from $0.73/gal to $0.63/gal over this scale-up.

More significant than production economies, which are really highly speculative at this point, are the transportation economies that arise from moving to more efficient forms of transportation as minemouth volumes reach the threshold level of production. In this example, early plants might be located near the end-use site, where the coal transport costs would be approximately $0.13/gal. Once plants are built at the mine mouth, but assuming that pipelines are not yet built, the logical transport mechanism would be unit train tank cars, where costs would be approximately $0.08/gal from the Green River region to Barstow, California. Finally, the long-run transport approach would be in high volume pipelines, where costs would be as low as $0.04/gal.

As a final measure of how the long-run production industry might differ from that in the near term, a calculation has been made of the effect of risk reduction by assuming that, as technical and market risks are reduced, the required return on invested capital falls from 25% in the near term to 20% in the mid term and, finally, to 15% in the long run. As shown in Table 4-1, the impact of these changes is substantial, lowering production cost on the study baseline 5000-ton/day methanol plant from $1.36/gal at 25% return to $0.73/gal at a 15% return. It is not inevitable, however, that this last step to 15% return on equity after taxes proves to be an acceptable rate of return, as it requires that the problems of risks and the general availability of capital be improved significantly from their current states. Rather, it is only presented to show the limits to the highly capital-intensive coal-based system.

Table 4-1. LONG-RUN WESTERN COAL-TO-METHANOL PRODUCTION COST POTENTIAL (1981$/gal)

	NEAR TERM 1982 - 1992	MID TERM 1992 - 1997	LONG TERM Beyond 2002
	5000 ton/day	10,000 ton/day	21,000 ton/day
PRODUCTION SCALING			
Capital Cost ($/gal)	0.73	0.67	0.60
Methanol Cost ($/gal)[a]	1.00	0.90	0.82
	California Plant Site	Unit Train Tank Cars	Minemouth Pipeline
TRANSPORTATION SCALING			
Transport Cost ($/gal)	0.13	0.08	0.04
Methanol Cost ($/gal)[b]	1.13	1.08	1.04
	Capital Return to Equity 25%	Capital Return to Equity 20%	Capital Return to Equity 15%
RISK REDUCTION			
Capital Cost ($/gal)	1.09	0.73	0.46
Methanol Cost ($/gal)[c]	1.36	1.00	0.73
	5000-ton/day California Site 25% Return	10,000-ton/day Minemouth Site Unit Train 20% Return	21,000-ton/day Minemouth Site Pipeline 15% Return
COMBINED EFFECT[d]			
Delivered Methanol Cost ($/gal)	1.50	0.98	0.60

[a]Plant gate costs with 20% returns.
[b]5000 ton/day plants with 20% returns.
[c]5000 ton/day plants.
[d]Successively higher plant scales, more efficient transportation, and lower required return.

The combined effect of all three cost reduction mechanisms in Table 4-1 illustrates the lower limits to coal-based methanol on a delivered basis to California in the long term. Achieving all three types of economies (high volume pipelines, economies of scale in production, and risk reduction) will take an absolute minimum of 20 years. The point is that the technical and market risks industry must take in the transition period and the effort needed by government agencies to help facilitate the environment for methanol are potentially worth the effort. Suggestions, however, that very inexpensive (unsubsidized) coal-based methanol is possible in the 1980s or early 1990s are grossly optimistic.

2. North Slope Natural Gas

In the study evaluation of resources for methanol for California (Technical Report, Chapter 3), the data indicates that there are sufficient North Slope gas resources to support a production level of about 8 billion gallons per year for over 30 years. This resource is, therefore, quite large relative to California demands (approximately 60% vehicle-mile equivalent of the projected California demand for gasoline in the year 2000). In the very long-term, however, it is clear that it is not a substitute for ultimately making methanol from coal. Even using all the North Slope gas for methanol conversion would sustain only about 8% to 10% of the U.S. passenger cars on a vehicle-mile basis.[19] From the perspective of this study, on the other hand, North Slope gas-to-methanol is a long-run option because a commitment of that scale implies that the methanol fuel option is accepted and over its early transition hurdles.

The production cost analysis has not been worked out to the same level of detail as the coal option because throughout much of this study the prospects for the gas pipeline seemed fairly good. Once the pipeline was committed, the methanol option would cease to be meaningful. More recently, the prospects have become more remote for the project to be initiated. The mood at this point seems to be to wait for the economic situation in the United States and the rest of the world to improve sufficiently to permit a better financing package to be assembled. In terms of delivered cost to California markets, the cost would certainly be higher than some smaller remote gas sites on the Pacific rim. First, conversion costs would be higher, resulting from the added difficulty of towing the barges to the North Slope, securing them on-shore, and operating them in a more difficult environment. If the total cost of the installed plant were 25% higher than the Cook Inlet plant and it were operated 310 days per year instead of 330 days because of weather conditions, the production cost impact would be to raise methanol plant gate costs to \$0.63/gal compared with \$0.53/gal for the Cook Inlet case. In addition, there would be pipeline tariffs for slug flow through the oil pipeline to Valdez of approximately \$0.05/gal to \$0.07/gal, and finally, the added cost of tanker transport to California ports. The total cost of the operation would be \$0.76/gal, as shown in Table 4-2, for gas brought to the plant for $\$1.00/10^6$ Btu.

Table 4-2. NORTH SLOPE GAS TO METHANOL (1981\$/gal)

	NATURAL GAS COST	
	at $\$1.00/10^6$ Btu	at $\$1.50/10^6$ Btu
RESOURCE COST	0.12	0.18
CONVERSION COST	0.51	0.51
PIPELINE TARIFF	0.07	0.07
TANKER TRANSPORT	0.05	0.05
TOTAL	0.75	0.81

[19]Assumes a long-run fuel factor of 1.6 gallons of methanol to 1 gallon of gasoline.

Thus, methanol made from North Slope gas is less expensive than early coal-based methanol plants, but does not have as low a long-run potential cost. For the next 10 years or so the most likely outcome is that the gas owners will continue to put a gas pipeline project together where the methanol gas can be co-mingled with less expensive gas. This approach has a very low market risk for the pipeline backers and the resource owners. While the cost per million Btu of converting North Slope gas to methanol and delivering it to California may be higher at $\$11.70/10^6$ Btu than the delivered gas price (reportedly $\$9.00/10^6$ Btu), the value of the respective products are quite different. By the year 2000 the respective market value of wholesale gasoline is projected to be over $\$13.00/10^6$ Btu in 1981 dollars in our baseline scenario, whereas natural gas is forecast to be only $\$8.06/10^6$ Btu. The real issue is the market risk involved in the two options. As long as the gas can be rolled in, even if its delivered cost is above the otherwise market clearing price, there is virtually no market risk to the venture. Methanol conversion, on the other hand, poses significant risks because the quantities involved are so large (8 billion gallons annually) that methanol must be a viable fuel when the project is started. A reasonable forecast at this point is that the delays necessary to ascertain if 8 billion gallons of methanol are likely to be demanded in the fuel market would require too much time for North Slope gas owners. The State of Alaska will not let them flare it and there is likely to be a limit reached on reinjection. Thus, from the perspective of those involved, the methanol option would appear to be a very distant second choice.

C. END-USE MARKETS

The dominant long-run market for methanol as a fuel is in light-duty passenger vehicles. That is not to say that there will not be other important markets, but they will be much smaller in size. In this smaller but important category methanol may be used in utilities in the period beyond 2000 for limited peaking requirements, and by industry as a boiler fuel in environmentally sensitive areas.

1. Vehicle Market

The real focus in the long-term is on neat methanol fueling of passenger cars. This potential market in California is extremely large, although the gasoline component of motor fuel consumption is expected to slowly decrease through time as a result of more efficient vehicles and an increased proportion of diesel cars. For the nation as a whole, annual motor fuel (gasoline) consumption is expected to drop from 113.4 (97.5) billion gallons in 1982 to 102.7 (71.4) by the year 2000. In California, gasoline consumption is forecast to fall from 10.6 billion gallons in 1982 to 8.3 billion gallons by the year 2000, and for diesel fuel the increase is from 1.9 billion gallons in 1982 to 2.9 billion gallons in the year 2000. For California, the relative changes in diesel and gasoline demands are illustrated in Figure 4-1.

The utilization technology for both gasoline- and methanol-fueled vehicles is expected to improve significantly by the year 2000. For conventional vehicles the improvement (approximately 30% over the 1982

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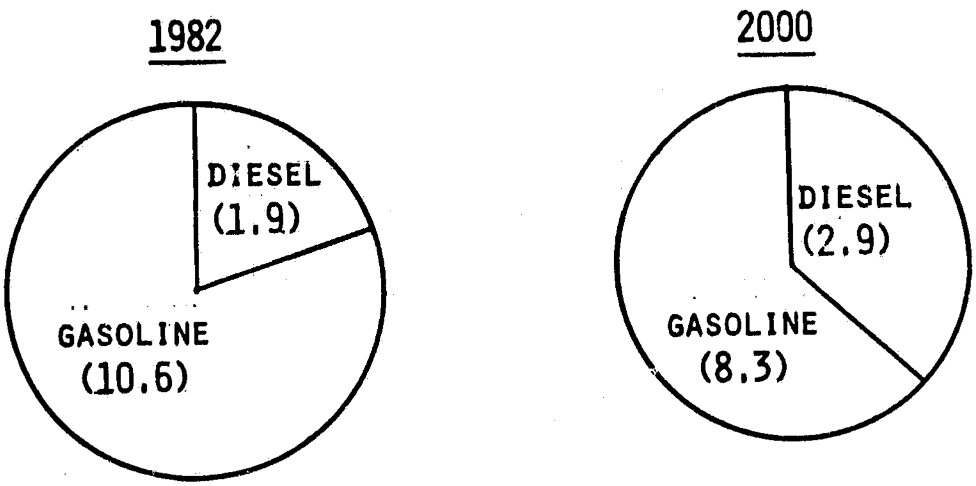

Figure 4-1. CALIFORNIA MOTOR FUEL DEMANDS (10^9 gal/year)

vehicle) will arise from aerodynamics, drive train and engine efficiency gains from compression ratio increases, leaning, and other changes. In neat methanol-fueled vehicles many of the above factors (e.g., aerodynamics and weight reduction) affect efficiency gains in a comparable manner. Significant differences occur, however, with respect to compression ratio, leaning, vaporization, and exhaust heat recovery. The potential in the long run (i.e., 2000) is for a net gain over the conventional baseline of about 10% without dissociation and about 28% if it is included.[20] In terms of the fuel factor, these two assumptions correspond to 1.86 and 1.60 respectively.[21] Thus, in the long run, dissociation is an important technical improvement necessary for methanol to maintain its fuel efficiency advantage (see Figure 4-2). Even if the conventional vehicle does not improve quite as dramatically relative to the study's conventional baseline, the fuel factor limit should be about 1.55 by the year 2000. Projections of fuel factors as low as 1.3 are in comparison to 1980 conventional vehicles and are, therefore, inappropriate measures of what can be accomplished relative to a realistic moving baseline.

[20]See Tables 8-10 and 8-11 in the Technical Report.

[21]See Table 8-11 in Technical Report.

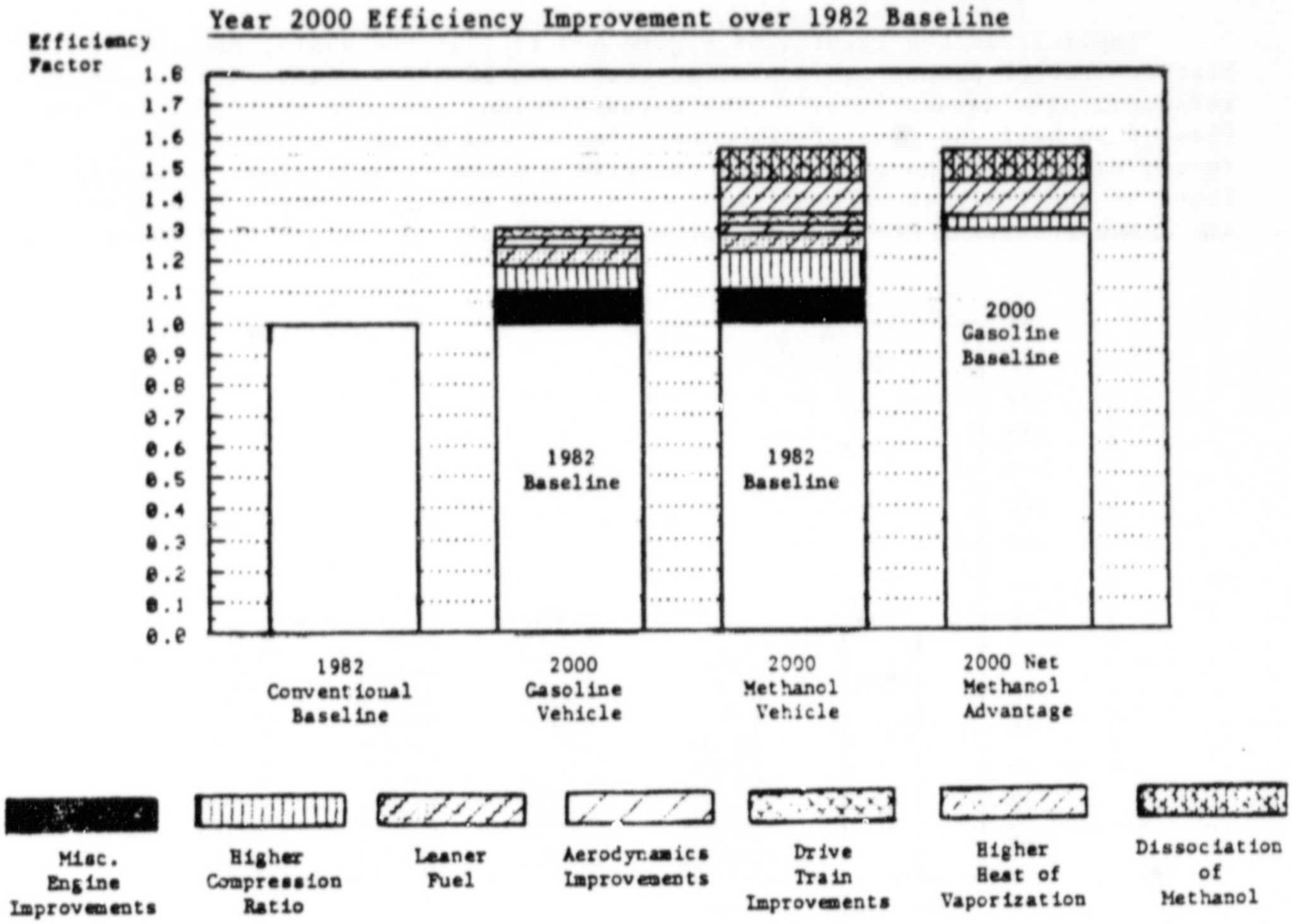

Figure 4-2. VEHICLE OVER-THE-ROAD EFFICIENCY: GASOLINE VERSUS METHANOL

2. Long-Run Competitiveness of Methanol

Given the fuel efficiency projections in Figure 4-2, it is necessary to combine these technical values with the study's fuel price projections to achieve a measure of the over-the-road cost of methanol versus gasoline vehicles. Four basic sources of petroleum products are compared with methanol as a transportation fuel: conventional oil, shale oil, methanol-to-gasoline (MTG), and Fischer-Tropsch gasoline. As shown in Figure 4-3, of the wholesale costs of transportation fuel from these four sources, only methanol is competitive with the base case oil cost. Both shale oil and methanol-to-gasoline are competitive with the high oil price scenario, but Fischer Tropsch liquids are uncompetitive under any of the scenarios. In addition, the high price scenario must be interpreted with some caution because the projected cost of the synthetic fuel plants has not been adjusted for the feedback effects of higher energy cost (Figure 4-3). Aside from feedstock cost feedback, there are additional feedbacks through transportation costs and the indirect costs of ramifications from higher oil prices as they filter through the economy. The subject of consistency in the high price scenario is detailed further in the Transition Analysis Section (Section V).

Implicit in the results of Figure 4-3 is that the shale, MTG, and Fischer-Tropsch plants are scaled at about the 50,000-ton/day size, based on reference case assumptions.[22] The methanol plant is sized at 10,000 ton/day (less than half the size of the other plants) and assumes a vehicle fuel factor of 1.6 gallons of methanol to drive a distance equivalent to gasoline. Thus, it appears that methanol is conclusively more competitive than MTG[23] and Fischer-Tropsch gasoline,[24] but more difficult to compare with shale

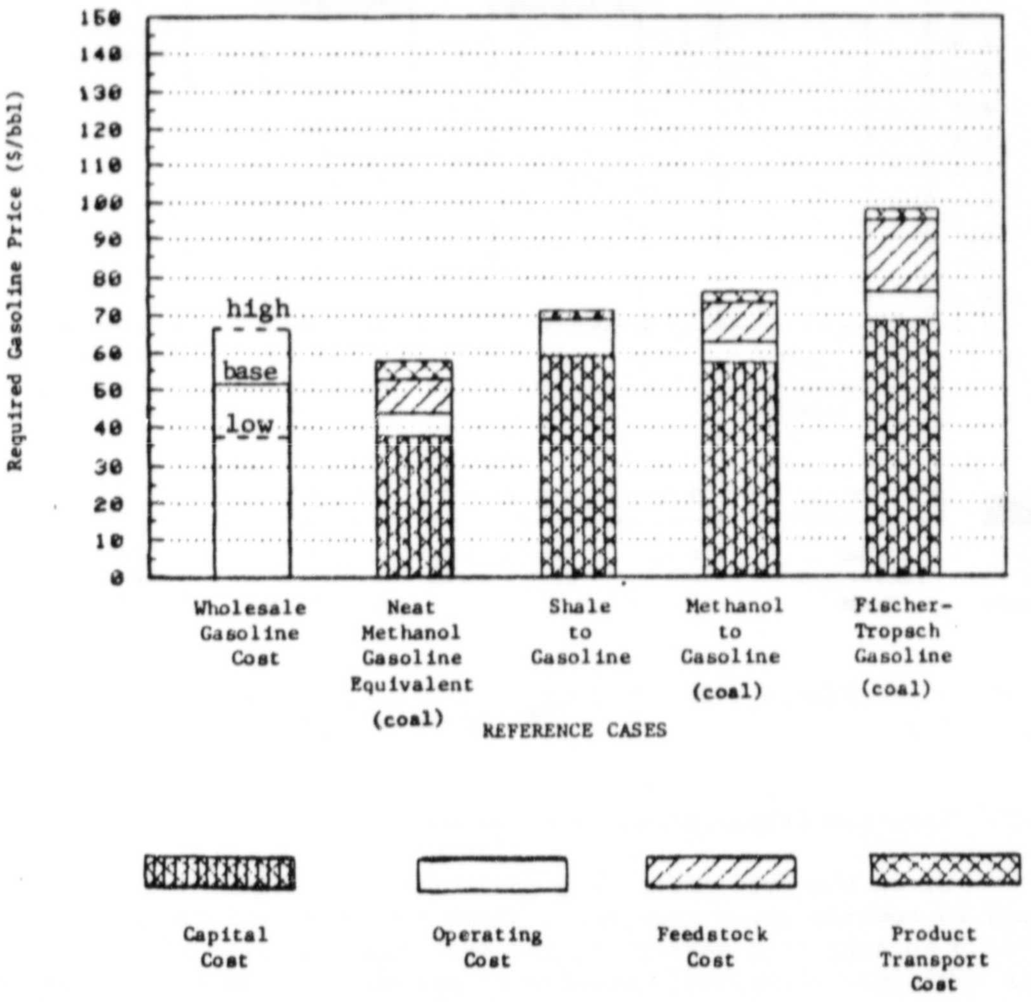

Figure 4-3. 1992 COMPARISON OF DELIVERED COSTS FOR SYNTHETIC GASOLINE ALTERNATIVES (1981$)

22See Table 4-26 of the Technical Report.

23The factor with MTG versus neat methanol is that their costs are highly correlated, having about 90% common processes.

24In this case, the cost difference is so extreme that no potential is seen for a reversal in these systems.

oil. In this latter case, neat methanol appears more cost-effective today, but much additional work remains before there is sufficient data to choose between them. In fact, a more likely outcome is that both of these synthetic fuels will be part of our fuel supply in the period beyond 2000, where the respective quantities of each produced will be determined when their marginal production costs are equalized at the market clearing price.

3. Long-Run Stationary Application Markets

In the long run (year 2000 and beyond), oil and natural gas will be used significantly less in stationary applications than today. For the nation as a whole, oil consumption in electric utilities will likely fall from over 2 quads to less than 1/2 quad over that period, while natural gas consumption is expected to fall from 3.8 quads in 1982 to 2.4 in 2000. For industry, oil demand is expected to drop from 4.8 to 3.9 quads and natural gas demand to fall from 6.5 to 6.0 quads in the same timeframe. These forecasts and the corresponding figures for California are summarized in Figure 4-4.

From the figure, it is clear that utility demands for oil will be small in this time period in California (about 30 trillion Btu or 460 million

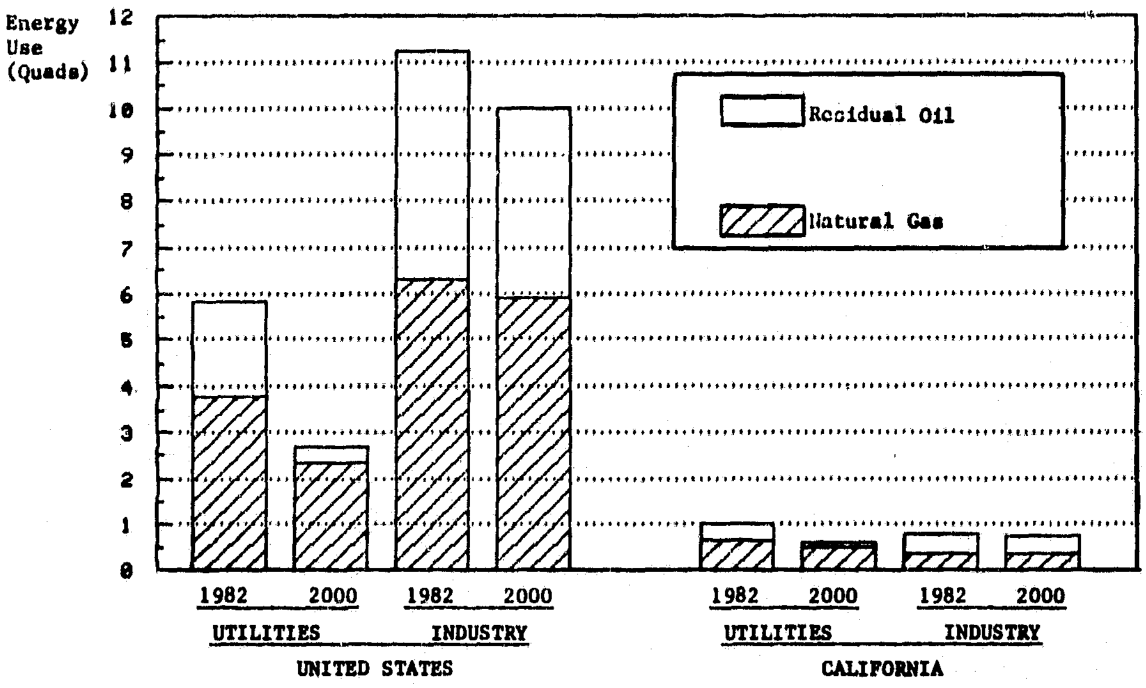

Figure 4-4. STATIONARY APPLICATIONS FUEL DEMANDS FOR ENERGY

gallons of methanol). Natural gas consumption, though larger (570 trillion Btu), should be available for utility use at prices which are too low for methanol to be competitive ($\$8.08/10^6$ Btu in the baseline case for 2000). In the high oil price scenario the study conclusions are reinforced: although natural gas prices will rise to $\$10.31/10^6$ Btu, natural gas will be more plentiful as a result of increased supply and reduced industrial demands. In addition, the higher natural gas prices will have a feedback effect on remote natural gas values, which will rise to market parity, less LNG conversion and transport costs. Thus, the prospects for methanol in the long-run electric utility market are very small unless regulation limits the access of utilities to natural gas.

In the industrial markets a similar pattern is evident in that natural gas remains the dominant fuel for the remainder of the century. As in the case of utilities, there is little prospect for methanol competing with natural gas on a Btu basis and thus the market potential is limited. Methanol may still be an important fuel for the growth of industry in metropolitan areas in California because environmental restrictions may limit growth in the absence of clean fuels.[25] Thus, although the quantity of fuel is quite small compared to national fuel consumption, there may be an important role for methanol in this period.

D. SYNTHETIC FUELS COMPETITION

In the long run, the marginal competition to neat methanol comes from other synthetic fuels. For stationary applications, this competition is from medium Btu gas, SNG, or synthetic fuel oil. For transportation fuels, as shown in Figure 4-3, the relevant existing competition is from shale, MTG, and Fischer-Tropsch gasoline. As the figure indicates, neat methanol does appear to be in the competitive range for transportation fuels.

For stationary applications, the role of methanol versus other synthetics is similarly clearcut, but with the opposite implications for methanol use. The most relevant competition is medium Btu gas, SNG, LNG, and conventional natural gas, as shown in Figure 4-5.

For delivering energy for repowering or for new combined-cycle plants, methanol does not appear to be competitive with some of the other options. This conclusion is more clearcut in the case of LNG and MBG because costs in the former case are reasonably well understood, while in the latter case there is significant process overlap with methanol derived from coal.[26] Thus, even

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[25]Although beyond the scope of this study, it is clear that Hawaii represents an interesting potential synfuels market for utilities and industry because it will remain dependent on liquid fuels and be relatively more vulnerable to an oil disruption scenario.

[26]Plant specifications and cost estimates for the synthetic gas options are from Table 4-26 of the Technical Report. The cost estimate for methanol is from Table 4-25 of the Technical Report for a 21,000-ton/day plant with reference case assumptions, except for 1997 start-up.

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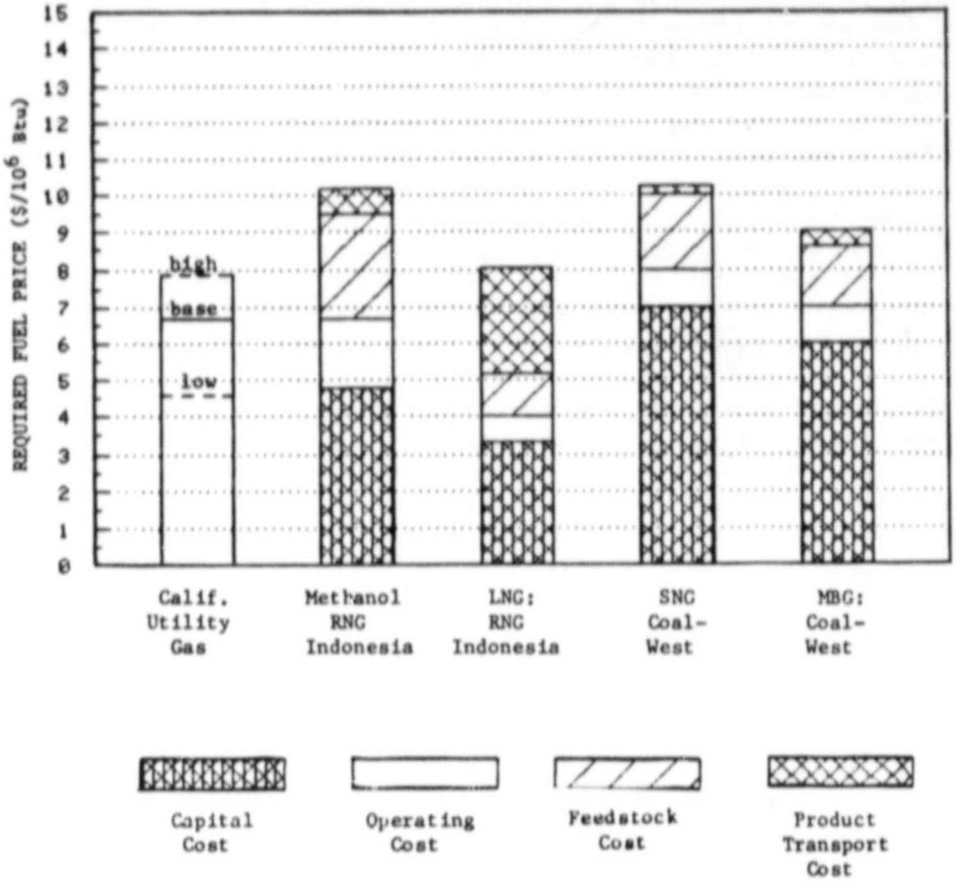

Figure 4-5. 1992 COMPARISON OF DELIVERED SNG AND NATURAL GAS PRODUCTION COSTS (1981$)

with the considerable uncertainty in estimating synfuel plant costs, there seems very little chance that methanol can compete with MBG in the long run or LNG in the intermediate term in stationary applications. The only market where methanol may have a significant advantage is where environmental problems are very restrictive and methanol proves to have advantages over natural gas in terms of NO_x emissions at the end-use point.

E. LONG-TERM MARKET SUMMARY

As a means to summarize the market potential for methanol in the 1997 timeframe, the relevant markets and sources are summarized in Figure 4-6. On the supply side, both coal and natural gas options are represented. For natural gas, the supply elasticity is such that quantities of 10,000 to 20,000 ton/day can probably be supplied before large supply cost increases take place. These cost increases result from increasingly higher feedstock acquisition and collection costs, and also from costs associated with longer

product transport times. As a result, these costs would increase until the potential for North Slope gas could be exploited (around 10,000 ton/day). Of course, if the gas pipeline to the North Slope is constructed, methanol will cease to be a relevant option. For coal-to-methanol, the figure shows how quantity might lower production costs for a period while production and transport economies are exploited. The lower bound of the coal-to-methanol region is for a 15% after-tax IRR, which might be applicable in the longer term after risks (both market and technical) are reduced. If a 20% after-tax IRR is required throughout the period 1982 to 1997, the upper bound of the coal-to-methanol region defines the applicable production costs. Shifts in product costs of quantitites at 10,000 and 20,000 ton/day correspond to economies associated with larger plants (e.g., 10,000 ton/day) and pipeline transport, which becomes feasible at 25,000 to 30,000 ton/day.

On the demand side, the highest value submarkets are for octane blending, but these markets are very small, totaling no more than 2000 ton/day. It is most interesting that light-duty vehicles should be in the competitive range for both remote natural gas and coal-based methanol if market and technical risks are reduced so that 15% after-tax returns become acceptable in the long run. The results in Figure 4-6 also show that the

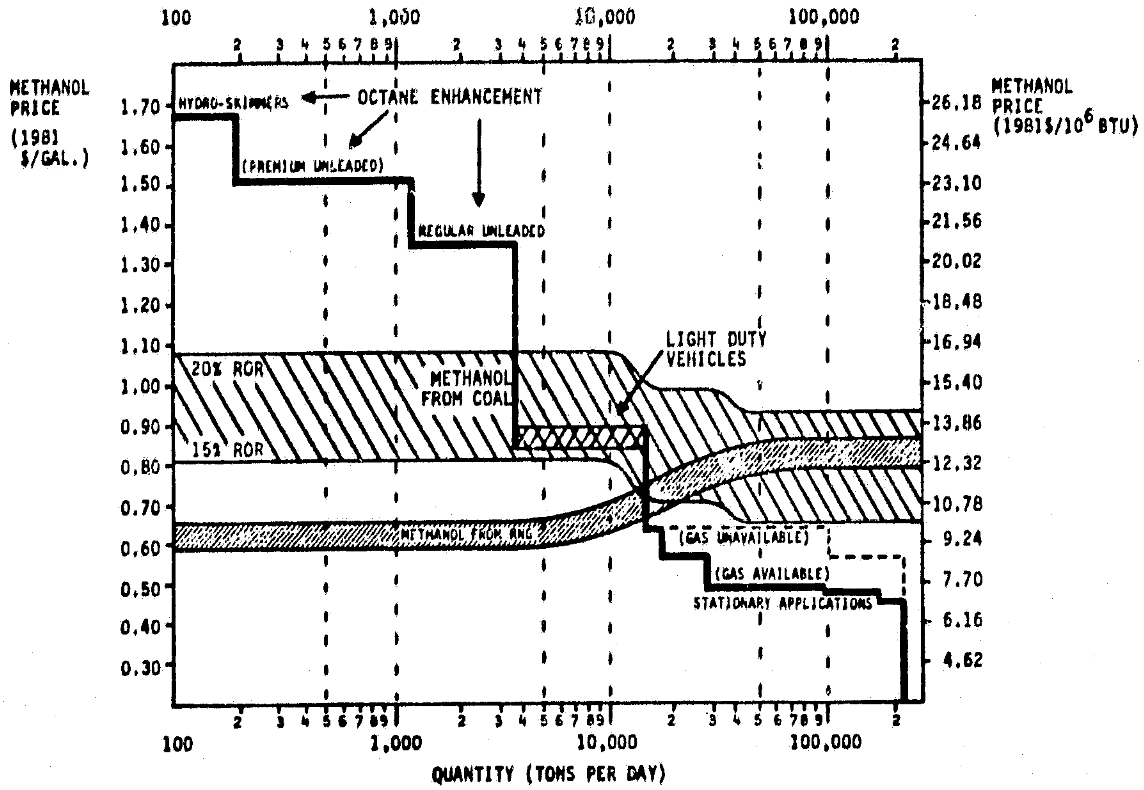

Figure 4-6. METHANOL FUEL MARKETS BEYOND THE YEAR 2000
(1981 $)

prospects for methanol use in stationary applications are not very optimistic in the case where natural gas is available. In fact, as strictly an energy source, methanol is not likely to compete with LNG or MBG as a fuel source for combined-cycle plants or for repowering oil-fired boilers. There may be a small utility role for methanol in dual-fueling plants under strict control for NO_x dispatch.

SECTION V

THE TRANSITION PERIOD

A. INTRODUCTION

The transition period is the most interesting aspect of the evolution of the methanol market because it is a timeframe in which production methods and sources will change, end-use technology will improve, and the fuel market in which it competes may also experience significant changes. The 10-year period from 1987 to 1997 is defined for the purposes of this study as the transition period in which major changes must occur if methanol is to be a significant fuel by 2000. Obviously, planning, testing, experimentation and policy changes might begin sooner, but the impact of these activities on the market will be felt in the 1987-1997 timeframe.

Given the starting point illustrated previously in Figure 2-2[27] for the bounds on the California fuel market for methanol in 1987, similar snapshots of utility, industrial, blends and neat transport fuel markets are made in this section for 1992 and 1997. Once again the intent is not to make a forecast, but rather to show the market potential in the various submarkets and the methanol prices at which these California submarkets become competitive. Highlighted in this section are: technological evolution in neat methanol-fueled vehicles versus gasoline-fueled vehicles, the impact of alternative fuel price scenarios on methanol viability, and changes in the utility fuel demand market. Also, production of options are analyzed and a comparison is made with other synfuel alternatives that might be competing with methanol in this timeframe.

B. 1992 METHANOL MARKETS

By 1992, the most important factor in the status of the methanol fuel market in California will be the competitive environment in which it must compete. The pertinent submarkets are blends, fleets, private passenger cars, industrial fuels, and utility fuels. All of these market potentials are shown in Figure 5-1 in terms of both breakeven prices and market sizes. Some significant changes are evident from the corresponding figure for 1987,[27] especially in the scale of the potential stationary applications market and the addition of a light-duty vehicle submarket.

1. Stationary Applications

a. <u>Fuel Substitution</u>. By 1992, the utility industry could have completed its testing and experimentation program and thus be in a position to use methanol widely if it is competitive with other fuels. Under the baseline fuel price scenario, an extensive market of approximately 58,000 ton/day is potentially viable at a methanol price delivered to California of $0.42/gal in

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[27]See Figure 2-2, p. 2-9 of this report.

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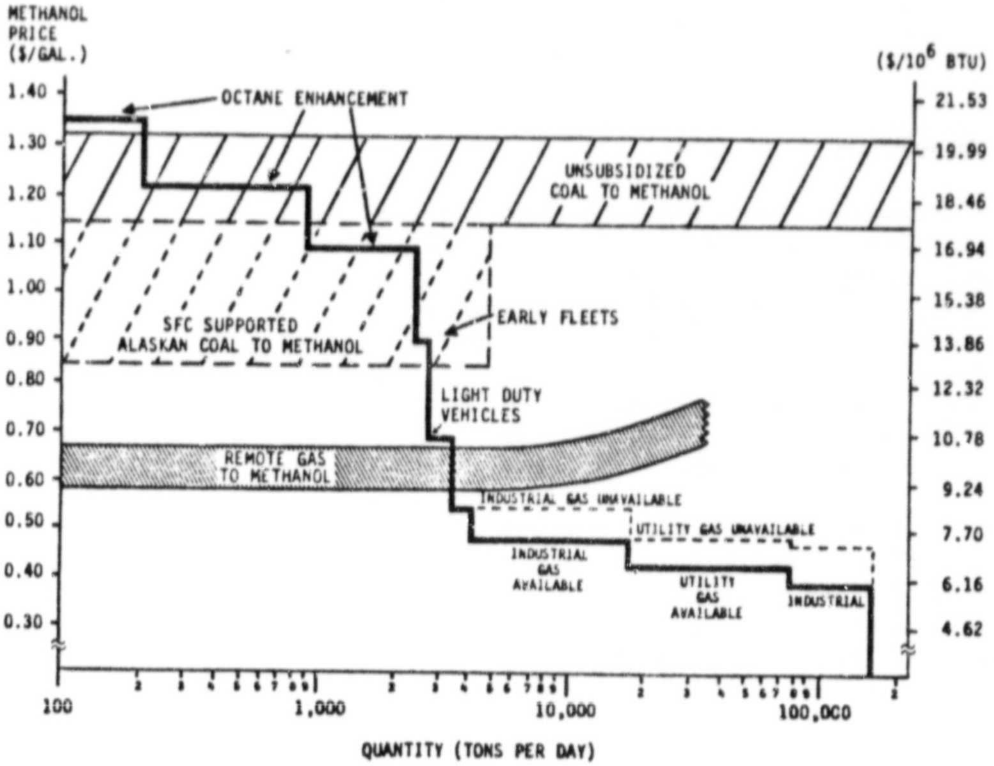

Figure 5-1. 1992 CALIFORNIA METHANOL MARKET (1981$)

1981 dollars. Some of this capacity (6000-ton/day methanol equivalent) is natural gas-fired and would allow a methanol breakeven price of $0.54/gal if natural gas were unavailable and distillate fuel was used as the substitute. It seems likely, however, that natural gas will be available during this period, thus making the $0.42/gal figure the appropriate target.

In the industrial market, the relevant competition is natural gas at $6.68/10^6$ Btu, residual oil at $7.03/10^6$ Btu,[28] and distillate oil at $8.55/10^6$ Btu, which corresponds to methanol prices ranging from $0.42/gal to $0.54/gal after correcting for efficiency changes, conversion cost, and local distribution. The bulk of this very large market (expected to be 88,000-ton/day methanol equivalent) is only cost-competitive at methanol prices of $0.42/gal or less, while a smaller submarket corresponding to about 8000 ton/day has a breakeven price of $0.54/gal, but only if natural gas is unavailable and distillate fuel is substituted. With natural gas available, which is the baseline assumption, the industrial market will all fall in the narrow range of $0.42 to $0.44/gal of methanol delivered to a central distribution point in 1981 dollars. At the plant gate, allowing $0.05/gal for transportation and unloading, the required price for methanol production is

[28]Residual oil with 0.5% sulfur.

$0.37 to $0.39/gal, which is significantly below the baseline production cost estimates.

Thus, with unsubsidized private methanol production ventures, it is not anticipated that methanol will compete in stationary applications on a fuel basis alone. Production cost incentives and environmental values may also lead to other bases for methanol use in stationary applications, and these possibilities are discussed later in this section.

b. High Price Scenario. An important consideration is whether the conclusion that methanol will not compete in stationary applications on a Btu basis holds under the more pessimistic oil price scenario. A rather surprising finding of this study is that the feedback effect of higher oil prices to methanol production costs may in fact make methanol less competitive in the high oil price scenario relative to utility fuels.

The baseline assumption is that utility gas would be $\$6.68/10^6$ Btu in 1992 (1981 dollars) and rise to $\$7.45/10^6$ Btu in the high oil price scenario.[29] The feedback effects come from four sources: feedstocks, process energy, construction costs, and product transport; these sources account for feedback effects on the delivered price of $0.04/gal, $0.01/gal, $0.03/gal and $0.01/ gal, respectively. Methanol production and delivery costs for an additional plant constructed after the oil price rise would therefore increase approximately $0.09/gal or $\$1.39/10^6$ Btu.[30] Thus, the competitiveness of methanol versus market natural gas is not enhanced by higher oil prices in utility markets.

c. Environmental Value of Methanol in Utilities. Those power plants that are environmentally restricted from operating at full capacity (e.g., Ormond Beach 1 and 2, Long Beach 8 and 9) have a potential premium that may be added to the fuel value of methanol. The calculation performed (see Chapter 9.D.9 in the Technical Report) was to estimate the value of operating these plants at their nameplate capacity on methanol versus their current restricted output, and attribute the value of that added capacity to the value of methanol. In 1981 dollars, the potential methanol premium for Ormond Beach as an example ranged from a low of $\$0.25/10^6$ Btu to a high of nearly $\$4.00/10^6$ Btu, depending upon the assumed gain in heat rate, the efficiency of the units displaced, and the value of adding capacity to the overall system. Full-scale testing must be done on methanol overfiring and on natural gas overfiring to resolve the actual benefits. It is clear from the sensitivity analysis done, however, that the issue of whether there is a heat rate gain and its value is crucial to the viability of methanol overfiring. Without this potential gain, methanol is very unlikely to overcome the $\$3.00/10^6$ Btu added cost expected over the likely oil and gas price in the mid

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[29]For 1997, the increase is from $\$7.48/10^6$ Btu to $\$9.30/10^6$ Btu in the baseline and high price scenarios, respectively.

[30]By 1997, the feedback effect would be $0.14/gal or $\$2.16/10^6$ Btu.

1980s. If this concept is validated in large-scale tests, the quantities involved for 10% overfiring at Ormond Beach and Scattergood would involve approximately 1500 tons per day of methanol, which is a significant quantity relative to methanol fuel use, but a very small percentage of utility oil and gas use.

Another environmental issue is the value that methanol would have as an alternative in meeting NO_x reduction requirements. The assumptions and results of this analysis are summarized in Tables 9-28 and 9-29 of the Technical Report. The approach was to identify three cases that would make it difficult for Southern California Edison to achieve its NO_x emission goals, which are in compliance with regulatory requirements. For each of these cases (no natural gas, no geothermal generation, San Onofre not available), different emission reduction options were evaluated (methanol firing, dual-fueling, repowering, selective catalytic reduction, low NO_x burners, etc.) that would bring the system back into NO_x compliance. The premium values for methanol beyond its Btu value as an environmental control option were then evaluated as ranging from $\$1.90/10^6$ Btu to $\$1.70/10^6$ Btu for dual-fueling with methanol versus selective catalytic reduction of oil-fired boilers. In the more likely case, however, of comparing methanol dual-fueling with low NO_x burners in 85% of the oil-fired boilers to replace geothermal capacity, the premium value for methanol is only $\$0.25/10^6$ Btu. It is important to note that all of these NO_x premiums are zero in the base case (that SCE's current program is maintained and is successful). A few hypothetical cases were examined to determine the consequences of the incremental cost of NO_x reduction in the event that a major element of SCE's current program is not fully implemented.

d. Overview. The potential for methanol as a fuel in stationary applications is very limited in the transition period because it cannot be produced competitively with pipeline gas or even LNG. This situation is actually strengthened in the high oil price scenario, where feedback effects in methanol production costs will offset likely increases in pipeline gas. Under the assumption that natural gas remains available to utilities (which appears highly likely), the margin for error between costs for natural gas and methanol is estimated to be sufficiently wide that methanol cannot compete on strictly an energy basis.

The only other rationale for using methanol for stationary applications in this timeframe would be that it has environmental value beyond its energy content. The problem with environmental premiums is that there are current programs in place that rely primarily on nuclear capacity, out-of-state coal generation, and renewables to achieve environmental compliance. Burning methanol within the Los Angeles air basin is neither as cost-effective as these options nor as environmentally benign with respect to NO_x and sulfur output in the basin. The one exception to the lack of environmental premiums is the case where plants are currently operated well below capacity due to NO_x output limitations. These few plants are really the only transition period methanol market in the utility sector.

In industrial markets the same basic conclusion holds. Methanol is not competitive on an energy basis and thus will only be used where very severe

environmental restrictions exist (but not so severe as to preclude methanol burning). For example, requirements that new emission sources only be permitted if they can demonstrate 10% reductions in net overall emissions may not encourage methanol adoption unless an efficient pollution offset market exists. In the latter case, firms in the Los Angeles air basin would have an incentive to seek out the most efficient mechanisms for abatement and then offer the emission deductions into the offset market. Thus, under the right policy, industry could use methanol effectively because a premium would be established for methanol use in the Los Angeles air basin.

2. Transportation Markets

The dominating potential use for methanol is as a fuel for the millions of automobiles and trucks that will be on the road in the year 2000. Between the present time and the year 2000, transitional markets may develop that can enable successful introduction of both methanol fuel and methanol-fueled automobiles into the private marketplace. Therefore, in addition to the examination of neat methanol as a fuel for private automobiles, several other transportation submarkets have been examined. These markets include methanol as an octane-blending agent for gasoline, the medium- and heavy-duty truck and bus market, and in the near-term, the light-duty commercial and public fleet vehicle market. The following sections present a short summary of the contents of Chapter 8 of the Technical Report.

a. Methanol Demand in Refining and Blending Submarkets. There exist two principal applications of methanol within the refining and blending submarkets: the use of methanol as one of the feedstocks in the production of MBTE, and its use with a co-solvent in gasoline blending. California demand for methanol for use as a feedstock to MBTE production will be very small or non-existent, due to the absence in California of high-concentration, high-volume sources of isobutylene feedstocks. If a major petrochemical industry develops in California comparable to that found along the Gulf Coast, this situation could change.

There will exist a small market for methanol as a gasoline blending agent by the smaller (topping and hydro-skimming) refineries. This market appears to be presently existent at current methanol prices but is mainly unfilled. However, the fraction of gasoline produced in California by such refineries is quite small (approximately 4%). For some of these refineries, octane number-of-barrel costs may be sufficiently high to justify the use of high-price co-solvents such as propanols if low price tertiary butyl alcohol (TBA) is not readily available. For the most part, however, it will be the availability of relatively low price TBA on the West Coast that will determine the magnitude of use of methanol as a blending agent in California. If all of the TBA produced in the United States were shipped to the California markets, approximately 70% of the gasoline produced in California could be blended with methanol. If methanol could be marketed 12 to 15 cents cheaper in California than Gulf Coast-supplied methanol, TBA use in California would be more likely and the blends market would grow faster. The most likely application of methanol TBA in California would be in the blending of higher octane unleaded gasolines by the larger refineries or the upgrading of regular grade to

premium grade by blenders or small refineries. Unless the front-end volatility of the gasoline into which it is blended is reduced, Reid Vapor Pressure limits may be exceeded and/or driveability may suffer. Because the small gasoline blender has little control over the front-end volatility of the gasoline he receives, the potential market is reduced. For the larger refineries, there is the potential to "back out" butane and reduce volatility; however, it may not be an economic solution to providing octane if the refinery's existing octane number-of-barrel cost is low. Compared to the production of a remote natural gas-based methanol plant of approximately 3000 ton/day, the potential demand from the blending in the refinery sector in California is rather small. For example, if 20% is assumed as a reasonable estimate for the amount of gasoline that could potentially be blended with methanol, the daily methanol demand is approximately 900 tons of methanol, or a little less than one-third of a single plant's capacity.

b. Methanol Fuel Demand from Private Passenger Vehicles. Methanol-fueled vehicles appear to have attributes similar to those of gasoline-fueled vehicles. Such vehicles could be built performance-equivalent, or perhaps superior, to gasoline-fueled vehicles, and the composition of tailpipe emissions from methanol-fueled vehicles could lead to improvements in urban air quality (Section VI). Furthermore, the methanol-fueled vehicle appears to have a thermal efficiency advantage over that of a gasoline-fueled vehicle. The basic question appears to be: Is the thermal efficiency advantage sufficient to overcome the relatively high methanol prices? The answer to such a question is dependent upon the petroleum price scenario that is chosen, and the efficiencies of methanol versus gasoline vehicles. Therefore, methanol-fueled vehicle viability is outlined below in terms of the three scenarios used in this analysis.

As is discussed in the Technical Report, methanol-fueled vehicles would be expected to have somewhat higher energy efficiency than gasoline-fueled vehicles and test results have, for the most part, confirmed that expectation. This efficiency advantage can be conceived as being derived from three effects:

(1) A higher effective octane number than gasoline, permitting higher and hence more efficient engine compression ratios.

(2) A leaner misfire limit, permitting leaner part-load operations than gasoline.

(3) An effect related to the higher heat of vaporizaton of methanol that reduces the heat transfer to the coolant and/or increases the volumetric efficiency of the engine.

The actual efficiency advantage of a methanol-fueled vehicle cannot be exactly specified because it is design-dependent. However, based upon published results of engine and vehicle research and testing, a range for the efficiency improvement can be estimated. A key factor in evaluating methanol efficiency gains, however, is that the conventional automobile will also improve its efficiency over the transition period. Thus, net gains must be evaluated against a moving baseline that may show significant improvements. These improvements are summarized in Figure 5-2.

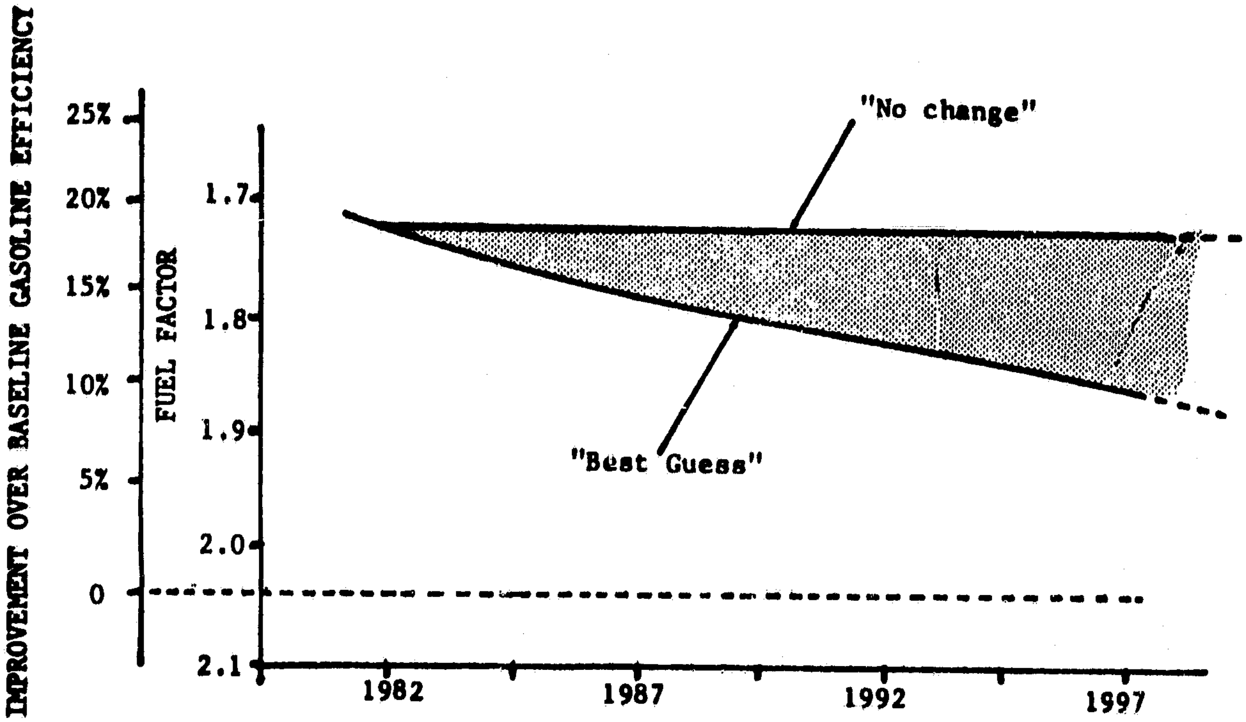

Figure 5-2. METHANOL FUEL FACTOR VERSUS GASOLINE

Two different types of methanol technologies are potentially available in the transition period: neat liquid methanol and dissociated methanol. In the former case, the efficiency gain would be 15% to 21% in 1982 and attenuate to approximately 10% by 1997 as conventional vehicles improve. This efficiency gain corresponds to methanol fuel factors of approximately 1.7 and 1.85 in 1982 and 1997, respectively. With dissociated methanol, there would be an additional efficiency gain, which improves the fuel factor to approximately 1.6 in the 1990s. The dissociated technology is in early stages of development and thus will not likely be ready for widespread use in vehicles (assuming successful development) until the late 1990s.

Thus, in the early 1990s, a reasonable estimate of methanol-fueled vehicle fuel factor[31] versus an improved gasoline baseline is in the range of 1.75 to 1.85. These estimates are less optimistic than some recent accounts in the technical literature, which do not appear to adequately reflect likely improvements in gasoline-fueled vehicles.

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[31]Fuel factor is defined as the gallons of methanol divided by gallons of gasoline to drive a given distance.

Under the low petroleum price scenario, liquid methanol-fueled vehicles do not achieve over-the-road cost competitiveness with gasoline-fueled vehicles in the foreseeable future. This is true for both remote natural gas-based methanol and coal-based methanol. Dissociated methanol-fueled vehicles become cost-competitive with gasoline in the early 1990s if the source of the methanol is remote natural gas. However, even with dissociated methanol technology improvements, coal-based methanol does not become competitive in the foreseeable future.

Using the baseline petroleum price scenario, liquid methanol-fueled vehicles become competitive with gasoline vehicles around 1990 if the methanol is assumed to be derived from remote natural gas. The competitive advantage in over-the-road costs after the early 1990s is not dramatic. (This implies a relative modest growth rate in the methanol-fueled vehicle market.) Dissociated methanol technology would move the breakeven date forward by several years, but more importantly, would significantly increase the cost advantage of methanol relative to gasoline. Under this baseline petroleum price scenario, coal-based methanol would not be competitive with gasoline in the foreseeable future, even with dissociated methanol-fueled vehicle technology.

Under the high petroleum price scenario, methanol-fueled vehicles would become competitive with gasoline-fueled vehicles in the late 1980s and, after this time, possess a significant cost advantage over gasoline. The high oil price scenario combined with dissociated methanol technology would permit coal-based methanol to be competitive with gasoline in the early 1990s. These results are summarized in Figure 5-3.

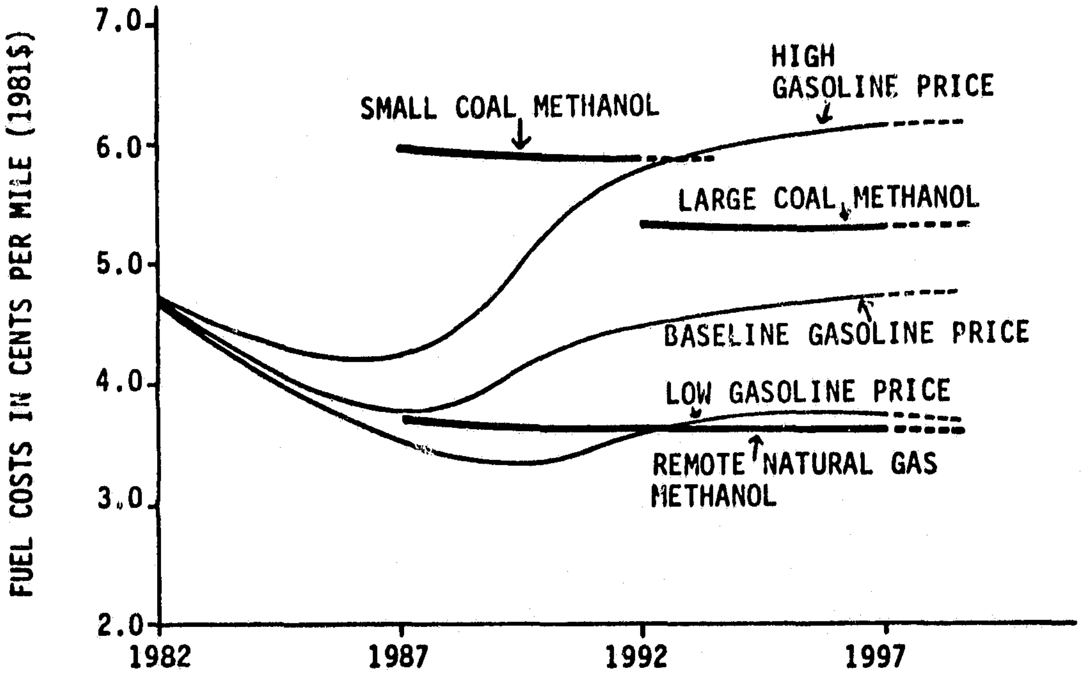

Figure 5-3. DISSOCIATED METHANOL VEHICLE VARIABLE FUEL COSTS

In summary, it appears that coal-based methanol is far too expensive to become cost-competitive with gasoline before the year 2000. If the source of methanol is remote natural gas, it appears that methanol-fueled vehicles could be competitive with gasoline-fueled vehicles in the 1990s, but the size of the cost advantage for the methanol-fueled vehicles versus gasoline-fueled vehicles may not be significant enough to give a major impetus to large-scale production of large quantities of methanol-fueled vehicles.

c. Methanol Vehicle Fleets. Fleet sales have been proposed as one way to begin a transition to general sales of methanol-fueled vehicles. Presumably, the first sales will be to a subset of fleet buyers with the following characteristics:

(1) Vehicles are commonly retained for a considerable period of time, hence resale value is not of great concern.

(2) The vehicles are fueled on-site or are fueled from a single contract source.

(3) Vehicles seldom, if ever, need more than a 200- to 300-mile range between refuelings.

(4) Visibility/public relations, petroleum independence, or some other attribute of a methanol fuel is of value to the fleet operator.

The growing methanol-fueled fleets will then, it is believed, generate a growing retail distribution system, which will in turn increase sales of methanol-fueled vehicles. However, such an approach depends only upon market forces and may thus be ineffectual. There may exist enough fleet operators who value the attributes of methanol to generate a demand for methanol-fueled vehicles. The demand may be sufficient to interest a vehicle manufacturer in the production of methanol-fueled vehicles. The resultant demand for methanol fuel, however, may still be far too small to cause a fuel supplier to establish retail capability in methanol.

A summary of the estimate of fleet market potential for the mid to late 1980s is shown in Figure 5-4, where the market is broken down into automobiles and light trucks or vans. Each of these vehicle types is then broken down into different types of users (police, government, utilities, etc.). Given the fleet sale rates indicated in Figure 5-4, the methanol production needed for fueling would be approximately 35 10^6 gal/year for automobiles and 98 10^6 gal/year for vans. Thus, the total methanol required is quite small relative to near-term supplies or marginal supply sources.

d. Heavy-Duty Methanol-Fueled Vehicles. Heavy- and medium-duty trucks and transit buses use approximately 0.30 quads of energy per year in California (approximately 2.3 x 10^9 gal/year of diesel fuel). This consumption is expected to approximately double by the year 2000. If this energy use was methanol-based, it would imply roughly 40-50 10^3 ton/day of methanol in 1980, and roughly 80-100 10^3 ton/day of methanol by the year 2000.

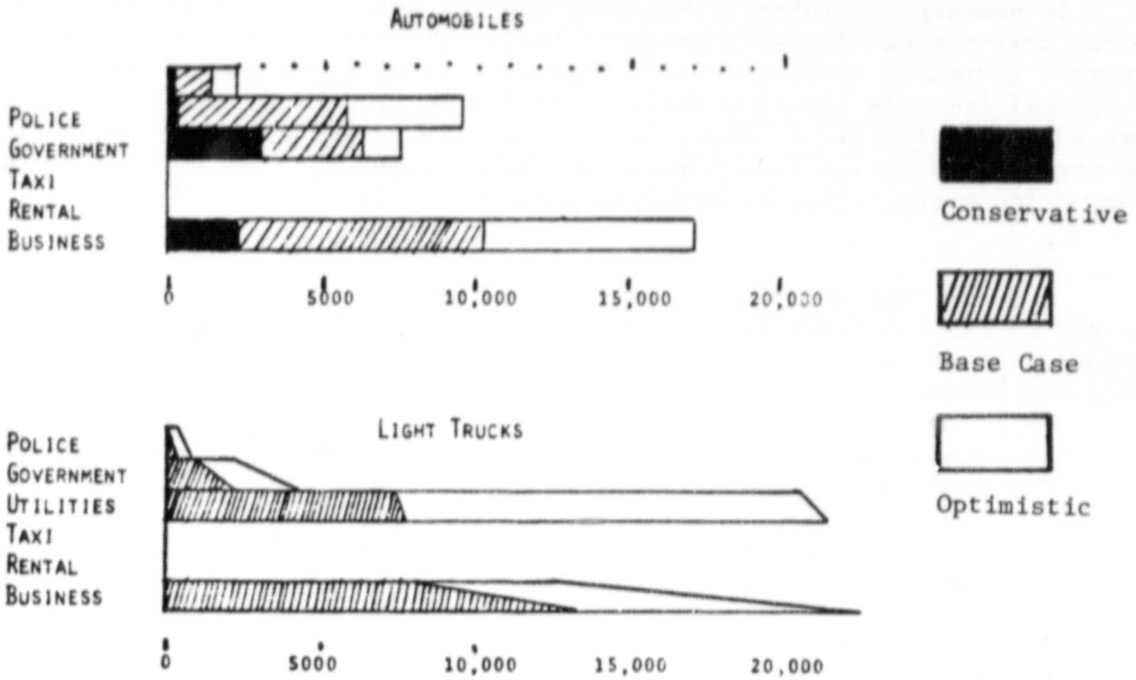

Figure 5-4. POTENTIAL MARKETS FOR NEAT METHANOL-FUELED FLEET VEHICLES

For analysis of possible transitions to methanol, this submarket is important not only because of its potential size but because the logistics of the fuel supply are simpler than those for private automobiles. On-site central refueling, combined with major interstate truck stops, can provide an adequate supply infrastructure, as it does with diesel fuel today. Methanol-fueled engines could penetrate this market more rapidly than private passenger cars. With the possible exception of transit vehicles, heavy-duty vehicle purchasers have a greater ability to specify the engine transmission system when purchasing new vehicles than do buyers of private passenger cars. While most transit vehicles and medium- and heavy-duty trucks are longer-lived than private cars, the engines are subject to replacement or major overhaul more frequently. For example, transit buses are subject to major powerpack (engine and transmission) overhaul or replacement every 150,000 to 200,000 miles. In normal operations, this would occur every 2 to 4 years.[32] Some heavy-duty truck applications are subject to even more frequent overhaul; in principle, conversion to a methanol-fueled engine could take place with any major overhaul or engine replacement.

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[32] Acurex Corporation, "Clean Coal Fuels: Alternative Fuel Strategies for Stationary and Mobile Engines," <u>Vol. VII: An Assessment of Methanol-Fueled Heavy-Duty Engines</u>, April 1982.

For the heavy-duty, methanol-fueled vehicle market potential to be realized, at least three requirements must be met:

(1) Methanol engines appropriate for medium- and heavy-duty truck and transit applications must exist in the domestic marketplace and sufficient "in-use" background must exist to ensure user confidence in the technology.

(2) A limited fuel-methanol supply infrastructure must be in place.

(3) Total costs for the methanol engine operation must be equivalent, or less, to those for the diesel engine.

There exist several methanol medium- and heavy-duty engines that are close to being commercially available. Several of these engines have been road tested, both in New Zealand and Germany. The UPS Texaco TCCS engine was originally designed to run on conventional fuels, but has been demonstrated to function satisfactorily on methanol.

Based upon the road test work to date, methanol-fueled vehicles do not appear to have a significant efficiency advantage over diesel-fueled vehicles in medium- and heavy-duty applications. (This implies that no significant market would be expected to develop until methanol and diesel reach approximate parity in the price per Btu. Under the baseline petroleum price scenario, Btu parity with distillate oils is not reached by low price remote natural gas-based methanol until well after the year 2000.)

e. Overview. As shown in Figure 5-1, the transportation markets are the submarkets where methanol can make a limited impact in the transition period. Low level blends (4.5%) of methanol with gasoline should be competitive at some level by 1992. The maximum methanol use would be about 3000 ton/day in California for this purpose, but actual use given TBA limitations will probably be smaller, about 900 to 1000 ton/day. The fleet market is the next increment in methanol demand which would be competitive at prices up to about $0.90/gal, but it would imply a maximum methanol demand of 1200 ton/day and a more likely demand of approximately 100 ton/day.

The passenger car market would also achieve parity in the early 1990s with the over-the-road costs of gasoline, although the margin would be slight. A key factor in this analysis is that only remote natural gas feedstocks yield methanol prices in the competitive range of fleets and passenger car markets. Because this feedstock source is not highly elastic, a very rapid penetration rate for methanol-fueled vehicles would lead to methanol production cost increases. At rates of penetration consistent with diesel vehicles in the period 1978-1982, remote natural gas is sufficient to supply both fleets and passenger cars through the transition period.

Rapidly rising oil prices consistent with the high oil price scenario induce feedbacks in methanol production costs that offset part of the apparent gain in competitiveness. As a result, with either the base case or high price scenario, methanol from coal does not appear viable through the transition period. In the low oil price scenario, light-duty vehicles do not become over-the-road competitive until beyond 2000, even for methanol from remote

natural gas. For this optimistic case scenario, the only viable methanol market is in blending for octane enhancement.

C. 1997 METHANOL MARKETS

The evolution of the methanol market is not striking over the remainder of the century, as shown in Figure 5-1. In the 1997 market, shown in Figure 5-5, the blends market is still a potential market for as much as 3000 ton/day of methanol. The light-duty vehicle market could expand to approximately 12,000 ton/day if it were to grow as fast as the diesel market has grown in recent years,[33] and after methanol achieves over-the-road competitiveness in the early 1990s. The extremely large utility and industrial markets still do

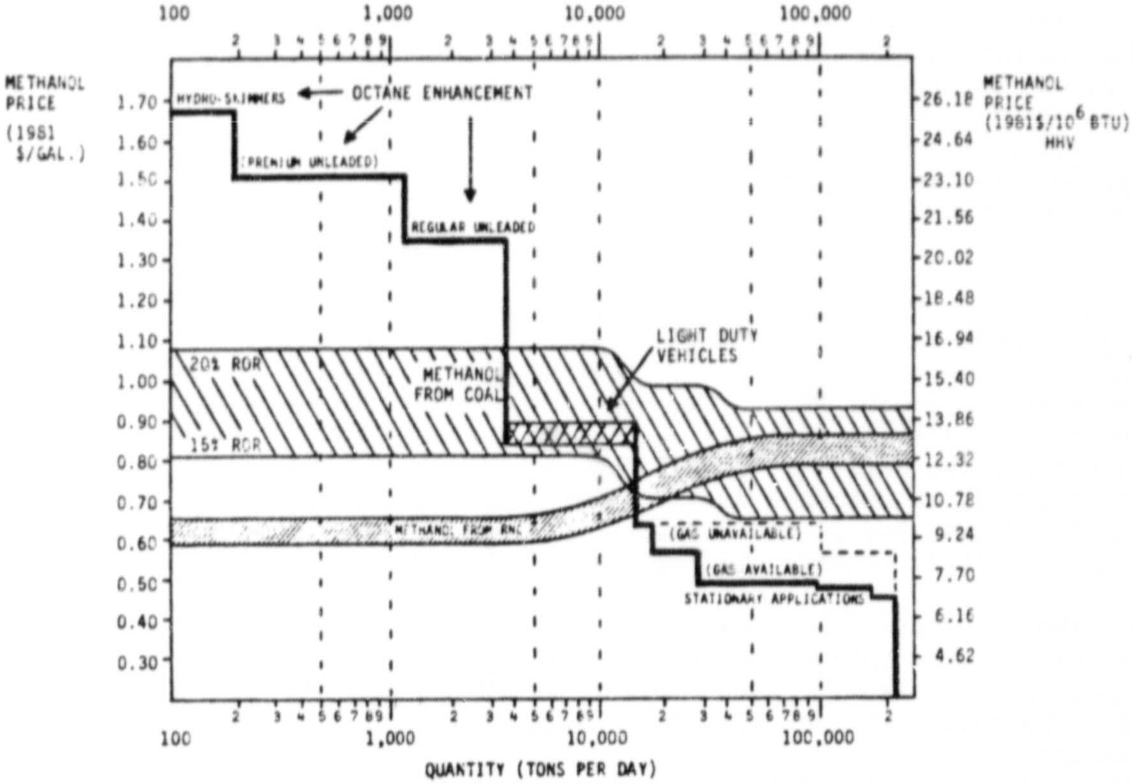

Figure 5-5. 1997 CALIFORNIA METHANOL MARKET (1981$)

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[33]Based on expansion of the diesel market share of new car fleets from 1978 to 1982.

not appear to be viable compared with natural gas and only marginally competitive even if natural gas is unavailable. But even if industrial and utility markets become viable in small quantities, it could be expected that demands above 40,000 ton/day would surely induce price increases that preclude larger stationary application markets. The high volume region of the remote natural gas production, shown in Figure 5-6, corresponds to Alaska's north slope, which could satisfy stationary application demands, but only at prices near \$0.80/gal or above. The most optimistic scenario for methanol from coal would be that risks are reduced, resulting in 15% returns becoming acceptable. This would require development of large (10,000-ton/day and up) minemouth plants with pipeline transport. But even these unrealistically optimistic assumptions result in prices of about $\$10/10^6$ Btu in 1981 dollars, which is above expected utility fuel costs. Thus, no market scenario is seen under which large-scale stationary application methanol use (e.g., repowering) could occur on a cost-effective basis. The strategy that these observations imply is to therefore focus on the transportation fuel market, where the high cost of existing fuels and the gain in vehicle efficiency will help the transition. Methanol use will grow slowly under this strategy, but it must grow slowly in order to prevent prices for methanol production from remote natural gas sources from being driven up too quickly.

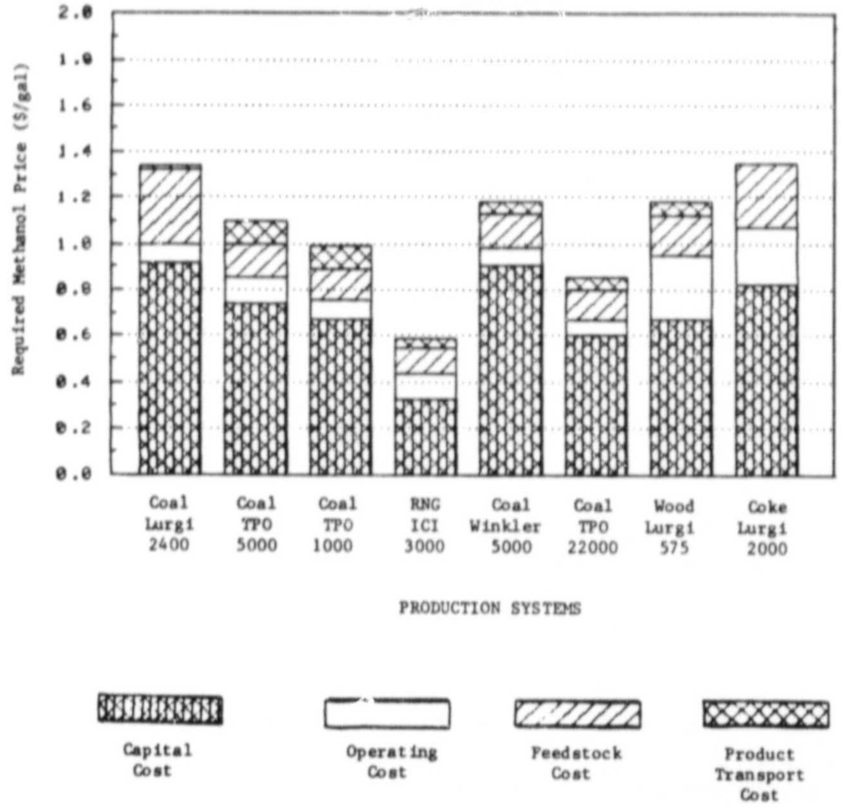

Figure 5-6. 1992 COMPARISON OF DELIVERED METHANOL COSTS FROM ALTERNATE FEEDSTOCKS (Ref. Case, 1981\$)

D. PRODUCTION

During the transition period in the late 1980s and early 1990s, the potential exists for new capacity to be constructed. As discussed in Section II, there are already capacity additions planned through 1987 based on natural gas feedstocks that may add as much as one billion gallons of excess capacity relative to projected chemical demands. Thus, there is an ample supply of methanol for early utility experiments, fleet use, and octane blending in the next few years. The discussion in this section will focus beyond 1987, when additional capacity will be needed. The options for incremental capacity expansions are examined, other synfuel alternatives are compared, the impact of the high oil price scenario on methanol production cost is evaluated, and the likely course for methanol capacity expansion is described.

1. Methanol Production Options

After detailed comparison of the methanol production costs from both California feedstocks (bioenergy, petroleum coke, heavy oil in rock) and other out-of-state resources (western coal, Alaskan coal and remote natural gas), it has been concluded that only two options would be important to California's transition period: remote natural gas, and SFC-supported coal-to-methanol plants (see Section IV). The production cost and transportation cost projections in Figure 5-6 clearly illustrate the relative cost of the options. Feedstocks, conversion technology, and capacity in ton/day are noted along the bottom of the figure for each system, with capital cost, operating cost, feedstock cost, and product transport cost denoted on the vertical axis. These systems are scaled to reflect system constraints, making the chosen system (natural gas) optimal in an overall end-to-end delivery system context. Based on a set of reference case assumptions (described in Chapter 4 of the Technical Report), remote natural gas has a clear delivered cost advantage to California markets. This advantage is not surprising; the capital cost requirements on an approximate basis for methanol conversion are: $1.50/annual gallon for barge-mounted natural gas, $3.00/annual gallon for coal, and $3.40/annual gallon for lignites. Obviously, coal-to-methanol can only be considered if the relative feedstock costs are significantly lower for coal or lignites than other options. While there will be a major feedstock cost differential after natural gas deregulation is complete that will preclude the construction of new methanol plants based on "pipeline" gas, there is still sufficient remote natural gas with opportunity costs below the market rate to satisfy transition period demands. If natural gas in remote areas can be purchased, collected, and transported to barge-mounted conversion plants for $\$1.00/10^6$ Btu to $\$1.50/10^6$ Btu, there will be no competitive incentive for the construction of coal-to-methanol plants.

A key factor in the conclusion that remote natural gas is the most important source for methanol in the transition period is the expectation that the markets will evolve slowly. Methanol from remote natural gas is not likely to be extremely elastic in supply. At large levels of fuel demand, production costs from this source would begin to rise for two reasons: longer transport distances to California, and higher collection costs in less developed remote sites. Although there is not sufficient data for a thorough analysis of this elasticity of supply issue, it is prudent to assume that,

beyond 10,000- to 12,000-ton/day capacity from remote gas sources, some cost increases would occur (e.g., higher transport cost from Indonesia versus Cook Inlet alone could account for \$0.05/gal to \$0.09/gal).

California feedstocks are not crucial to the transition period because they are either too expensive or too small to make a significant impact as a fuel. In the case of petroleum coke and heavy oil in rock, the problem is the feedstock cost. At $\$1.80/10^6$ Btu and a plant that is similar to a coal-to-methanol plant, petroleum coke would be uncompetitive with remote natural gas sources. Heavy oil in rock would be even more expensive; at a minimum of $\$4/10^6$ Btu, it would be too expensive to even consider as a methanol feedstock. The only indigenous source that may compete on a cost basis is bioenergy. There are some new gasifiers being developed specifically for wood feedstocks which will be manufactured and simply unloaded at the conversion sites that promise to reduce costs below the estimate in Figure 5-6. The problem is that these feedstock sources are not large enough or concentrated enough to be a major portion of California's fuel supply. Thus, although there may be some cost-effective methanol from bioenergy, it is not a critical part of the supply picture.

Aside from remote natural gas, the only other major source for California methanol in the transition is SFC-supported coal-to-methanol plants. The effect of loan guarantees and price supports would be sufficient to bring the minimum selling price from an Alaskan coal plant down to approximately \$0.81/gal delivered to California. At such a price the product would have some difficulty finding a market for a 4000- to 5000-ton/day output. Even with premiums for environmental operation, utilities could not justify such a high methanol price. Only the blends market might be willing to pay this high a price, but they could probably get other sources at lower prices as long as imports for blends are not subject to import duties.

2. Synfuel Alternatives

There are other synthetic fuel options that are potentially available to compete with methanol in either utility or transportation markets. Those which could be commercial in the next 15 years are shale oil, Fischer-Tropsch indirect liquefaction, methanol-to-gasoline as transport fuels, and SNG or medium-Btu gas in utility markets. These options have been evaluated in a consistent manner with a common set of assumptions (Section 4.C, Figure 4.3). These results have some definitive implications: (1) methanol-to-gasoline is considerably more expensive than neat methanol on a per mile basis; (2) Fischer-Tropsch gasoline is so much more expensive than any of the other options that it is not viable as a synthetic option for California. Although there is significant uncertainty in projecting synthetic fuel costs, the high correlation between methanol and methanol-to-gasoline costs indicates that these conclusions would be valid under most reasonable sensitivity assumptions. Similarly, the wide differences between Fischer-Tropsch liquids and neat methanol improve confidence in neat methanol as a superior fuel. From a production cost viewpoint, the edge of methanol over gasoline from shale oil is less significant. The processes are not closely related, nor is the margin so great that one dominates the other. A conclusion has been drawn that when environmental issues, however, are added to the cost evaluation, the edge is

clearly to neat methanol from California's perspective. As a national strategy, on the other hand, these and other synthetic fuels should be examined further.

3. High Oil Price Scenario Feedback

One area that is often overlooked in evaluations of new technologies is that the sensitivity of the competitiveness of new systems to higher energy prices also has a feedback to the production cost as well. In the case of methanol production, the high price oil scenario may be expected to affect production costs in three distinct ways. First, rising oil prices caused by continued political distruptions in the Middle East will tend to raise the feedstock cost of methanol production. Second, large-scale energy projects are themselves energy-intensive in terms of moving men and equipment to remote sites, supporting them, and in indirect energy usage due to the manufactured equipment and subsystems needed for the processing plant. Third, the operation of these plants over their lifetime would cost more for process energy valued at the opportunity cost of the higher price scenario. Thus, it is not necessarily true that higher prices and hence other energy costs greatly accelerate the competitiveness of synfuels. There are offsetting effects that partially mitigate the direct impacts.

In the case of methanol from remote natural gas, the mechanism by which feedstock costs rise is that remote gas can be converted to LNG and substituted for pipeline gas at end-use centers. A high oil price scenario leads to increases in market gas prices because these fuels are close substitutes in utility and industrial markets. In 1992, for instance, the increases in refinery acquisition oil and gas prices from the base case to a high oil price scenario are $\$6.68/10^6$ Btu to $\$7.45/10^6$ Btu for natural gas and from $\$7.54/10^6$ Btu to $\$9.90/10^6$ Btu for oil. These energy price increases could induce an overall increase in remote natural gas-to-methanol production cost from \$0.58/gal to \$0.66/gal. First, as pipeline gas rises in value, the remote resource may rise in value as well. An estimate of this increase was made by backing out the LNG conversion cost and transport cost from the pipeline gas price in the high oil scenario. The net difference indicated an increase of $\$0.50/10^6$ Btu in the value of the remote gas resource, which in turn increases methanol production cost by \$0.05/gal. Second, there would also be a small increase in the cost of barge-mounted plants which, of course, utilize process energy (mostly oil if made in Japan) that would cost more after the price increase. The potential feedback effects are hypothetical because a detailed analysis of the capital cost feedback effect is beyond the scope of this study, and even the remote gas cost would depend on the costs and alternative options in each specific gas field.

In coal-to-methanol plants, the source of the feedback comes more strongly from capital costs rather than feedstocks. Using the Texaco Coal Gasification Process 5000-ton/day plant as an example, the total feedback in 1992 would be an increase of \$0.11/gal and \$0.13/gal in 1997 based on a recent study. These feedback effects could offset much of the gain in apparent competitiveness resulting from high oil prices. This type of feedback may be a partial explanation for why shale oil prices seem to stay always slightly

above oil prices, even after large price jumps occur. The effect applies to all synfuels, and methanol is no exception.

Thus, although the specific values of the feedback impacts above are only rough estimates of the actual feedback that might occur, the more general caution that high oil prices would be partially offset by increases in methanol production costs seems quite sound.

4. Overview

The major findings in the production cost analysis are that:

(1) Methanol is most efficiently produced from remote natural gas in the transition period.

(2) Production costs from remote natural gas vary from the reference case of \$0.53/gal in 1992 up to \$0.66/gal at a 25% return and down to \$0.42/gal at a 15% return.

(3) The quantities of remote natural gas available on the Pacific rim at \$1.50/10^6 Btu or less appear sufficient to support California's transition period demands.

(4) Rapid expansion of methanol supply from remote gas resources will induce price increases as longer transport and higher collection costs are incurred.

(5) California resources are not critical to a methanol fuel transition.

(6) Methanol does appear to be in the competitive range with shale oil and to be significantly cheaper than methanol-to-gasoline or Fischer-Tropsch liquids.

(7) A high oil price scenario will induce some methanol production cost increases, which offsets some of the gains in viability.

(8) There does not appear to be a case in which unsubsidized coal-to-methanol plants become commercial before the year 2000.

As a result of these findings, some general conclusions can be formed. California needs to encourage the creation of an infrastructure to import and unload methanol within the state with emphasis on port facilities in the near term and pipelines in the long term. Attempts to favor the use of in-state feedstocks will only slow the methanol transition by raising methanol production costs. Similarly, attempts to stimulate rapid methanol use will induce increases in methanol production costs. It will take at least until the turn of the century for a fully commercial coal-to-methanol industry to become viable. Thus, in the interim transition period, remote natural gas must satisfy fuel demands. There is enough remote natural gas on the Pacific Rim at acquisition prices that will range from \$1.00/10^6 Btu to \$1.50/10^6 Btu

to supply likely fuel demands on the West Coast for fleets and octane enhancement. Artificial demand created by regulations to induce greatly increased methanol use (i.e., 50,000-ton/day) will lead to rising methanol supply costs as longer transport and higher remote gas collection costs are incurred. Thus, from the production side of the market, a relatively slow transition period is implied. A critical factor in tying together the supply and demand analyses is that coal-to-methanol production costs are a very important issue in the mid-term period, even though there are less costly near-term production options. The incentive to begin the investments in production and utilization equipment necessary to have a major commitment to neat methanol vehicles requires that coal-to-methanol production costs look attractive in the time horizon of 10 to 15 years. The analysis done in this study indicates that the actual time horizon at this point in time looks much longer. Thus, although there are less costly sources of methanol (remote natural gas, petroleum coke), the potential quantities at low prices are too limited to induce any significant transition.

SECTION VI

AIR-QUALITY IMPACTS OF METHANOL

A. INTRODUCTION

In this section, a screening analysis of likely impacts of methanol fuel on the air quality of the South Coast Air Basin is described. The Basin includes all of the populated areas within the counties of Los Angeles, Orange, Riverside, and San Bernardino. Some 11 million people, about one-half of the population of California, live within this area. The region has persistent and severe problems of air pollution due to a combination of factors: large amounts of pollutants are released into the atmosphere over a relatively small area; the mountains to the north of the Basin act as a barrier to the horizontal dispersion of pollutants; and for many days of the year, the existence of a temperature inversion layer confines the pollutants within a layer of air whose thickness is typically between 1000 and 2500 feet. The smog-forming reactions are initiated by sunlight and promoted by warm temperatures. Thus, smog is most severe during the long, hot days of summer.

There were several reasons for selecting the South Coast Air Basin as the case for assessing the impact of methanol fuel on air quality. In addition to the heavy population that suffers from the effects of pollution in this area, the availability of extensive compilations of emissions and meteorological information enabled the application of rigorous analytical procedures. For example, past and future estimates of pollutant emissions are summarized in the Air Quality Management Plan (AQMP), 1982 Revision, issued by the South Coast Air Quality Management District (SCAQMD). However, the scientific basis for the analysis of air quality and the conclusions to be drawn from that analysis are quite general.

B. AIR-QUALITY MODELING CALCULATIONS FOR OZONE AND FORMALDEHYDE

Over the last 20 years, researchers at the California Institute of Technology have made efforts to understand the chemical and physical processes that lead to the formation of photochemical smog. Some of the information obtained from that work has been applied to the development of models that simulate air quality in the Basin. One such model was developed at Caltech by McRae and Seinfeld. The air quality model calculates the amounts of secondary atmospheric pollutants such as ozone and peroxyacyl nitrates (PAN), given the emissions of reactive organic compounds (ROC) and oxides of nitrogen (NO_x) that enter the atmosphere from various sources such as automobiles, stationary power plants, solvents, and petroleum production, marketing, and refining operations. Ozone is widely accepted as a good index of all the complex reactions that take place among reactive hydrocarbons and NO_x in the polluted atmosphere. The ROC are divided into six classes, according to reactivity. For this analysis, the model was further adapted in order to treat methanol as a specific pollutant. The methanol chemistry was included in the model for completeness even though, as is shown later, methanol contributed relatively little to the formation of ozone. Thus, the model was able to distinguish seven classes of reactive organic compounds: alkanes,

ethylene, other olefins, formaldehyde, other aldehydes, aromatics, and methanol. The various ROC have different rates of reaction with NO_x and with the oxygenated species that promote the formation of photochemical smog. The model is described in detail in technical papers written by its authors.[34] It uses a Langrangian form for the representation of the equations of motion that describe the diffusion and convection of chemical species within the modeling region. It calculates the concentrations of chemical species along a given trajectory of an air parcel traversing the South Coast Air Basin. This computational method is generally faster than the alternative method of calculating those concentrations for every position within the Basin. In order for the model to give the concentrations of chemically reactive species, three major input components are required: (1) a meteorological description, such as wind speed and trajectories and vertical temperature variation; (2) a source description of the temporal and spatial distribution of emissions for all significant pollutant sources; and (3) a kinetic mechanism describing rates of atmospheric chemical reactions as a function of concentrations of various species present.

The meteorological description must account for the interactions among the various components. For example, temperature variations affect the inversion height, which in turn influences the transport of chemical species in the atmosphere. The emissions data must be accurate and detailed and specify emissions from diverse sources. The data must also be well structured so that emissions from one source can be varied without altering the remainder of the emissions. The model has previously been validated by comparing its predictions with observed atmospheric data and with the results of smog-chamber experiments. Out of 15 species of pollutants predicted by the model, NO_2 and O_3 were used to provide the most rigid test of the model's accuracy. The predictions were consistent with observed data.

After the model had been modified to include the chemistry of methanol, no additional validation runs were made because, as methanol had never been a component of the atmosphere of the Basin, there were no past atmospheric pollution data with methanol as a major pollutant. In addition, no suitable smog-chamber data were available for comparison with the predictions of the modified model. In the only published smog-chamber experiments with gas mixtures containing methanol,[34] not enough information was provided to enable a simulation of the experiments using the modified McRae-Seinfeld model. Nevertheless, the study is confident that the equations upon which the model is based correctly represent the chemistry of methanol and that the modified model is correct.

All calculations were based on the projected emissions of pollutants for the year 2000. At that future date, the potential benefits of existing pollution-abatement regulations would have been realized. At the same time, it is a feasible date by which, if methanol were to become an important fuel in California, air quality effects from this change would be felt. Calculations were performed to indicate the likely effect on air quality of using methanol as a substitute for gasoline. No estimates were made on the use of

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[34]See Reference Section, Chapter 6 of the Technical Report.

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methanol for stationary power plants or diesel vehicles, because the economic analysis, described elsewhere in this report, has indicated it is unlikely methanol would be used in stationary plants and diesel vehicles because the projected price of methanol in the year 2000 would not be competitive with the established fuels for these applications. The two main environmental effects of using methanol as a fuel for stationary power plants would be to reduce emissions of NO_x and SO_x. It was assumed that NO_x emissions from stationary sources would be kept within the limits imposed by existing regulations using any available economical means, including the use of methanol.[35] Consideration was given, however, to the effects on ambient concentrations of sulfates from the use of methanol in power plants and in industrial and commercial boilers.

1. Emission Inventories

Input data of emissions were prepared for two base cases and for four methanol cases. The two base case inventories were as follows. The first set of figures were taken from the projections made by the South Coast Air Quality Management District and published in their Air Quality Mangement Plan. The second base case inventory was obtained using Caltech CMAP calculations of emissions for highway motor vehicles and the SCAQMD projections for all other sources. The purpose of the CMAP inventory was simply to provide a means of checking the SCAQMD figures.

In developing the methanol case inventories, the substitution of methanol for petroleum-derived fuels was considered under four sets of assumptions, which were designated as Cases A through D. Those cases were defined as follows:

Case A. Substitution of methanol-fueled vehicles for all gasoline-fueled vehicles on the assumption that total, lifetime-average exhaust emissions for methanol-fueled vehicles and gasoline-fueled vehicles are equal. Calculation based on SCAQMD-projected emission inventory for the year 2000.

Case B. Substitution of methanol-fueled vehicles for gasoline-fueled vehicles on the assumption that total, lifetime-average exhaust emissions of reactive organic gases for methanol-fueled vehicles and gasoline-fueled vehicles are equal, but that the methanol-fueled vehicles have lower emissions of NO_x than the gasoline-fueled vehicles. Calculation based on SCAQMD-projected emission inventory for the year 2000.

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[35] Utilities in the South Coast Air Basin and in the Ventura County Air Pollution Control District are required to reduce their NO_x emissions by 60% by the year 1990. Use of methanol in some units could be included as part of an overall strategy to satisfy this requirement and could lead to payment of a premium for methanol.

Table 6-1. TOTAL EMISSIONS BY REACTIVITY CLASS FOR DIFFERENT BASE CASES AND METHANOL CASES (ton/day)

COMPOUNDS	BASE CASES		METHANOL CASES			
			SCAQMD INVENTORY			CMAP INVENTORY
	SCAQMD	CMAP	CASE A	CASE B	CASE C	CASE D
Formaldehyde	16.6	17.3	74.7	74.7	32.8	64.0
Other Aldehydes	36.4	37.2	36.4	36.4	36.4	37.2
Aromatics	208.7	251.1	113.2	113.2	113.2	118.4
Ethylene	41.9	53.2	22.3	22.3	22.3	25.6
Olefins	80.0	101.6	41.9	41.9	41.9	49.8
Alkanes	704.8	797.1	576.9	576.9	568.5	618.4
Methanol	0	0	225.7	225.7	137.5	346.6
Oxides of Nitrogen	920	990	892	768	768	999

Case C. Substitution of methanol-fueled vehicles for all gasoline-fueled vehicles on the assumption that total, lifetime-average exhaust emissions of NO_x and of reactive organic gases for methanol-fueled vehicles are 50% lower than corresponding emissions from gasoline-fueled vehicles. Calculation based on SCAQMD-projected emission inventory for the year 2000.

Case D. Substitution of methanol-fueled vehicles for all gasoline-fueled vehicles on the assumption that total, lifetime-average exhaust emissions for methanol-fueled vehicles and gasoline-fueled vehicles are equal. Calculation based on CMAP-projected emission inventory for the year 2000.

The calculated emissions data for each of the above methanol cases and the base cases are shown in Table 6-1.

In Case A, the assumption of equal emissions for methanol-fueled vehicles and gasoline-fueled vehicles was very conservative. It was made in order to establish a "worst-case" scenario for methanol, because emissions from future commercial methanol-fueled vehicles could not be accurately predicted.

The assumption of lower life-time emissions of NO_x for methanol-fueled vehicles (Case B) is based on the reported fact that methanol-fueled vehicles can produce much lower NO_x emissions. In general, a reduction in NO_x emissions is achieved at the expense of fuel efficiency. These calculations

were made in order to show what could happen and not necessarily what would happen in practice.

Among hydrocarbons, the methanol and formaldehyde emitted by methanol-fueled vehicles are more easily oxidized by exhaust catalysts than are the hydrocarbons in gasoline exhaust, such as aromatics and alkanes. In addition, there is good reason to expect that (1) the catalyst used for methanol exhaust would have a longer life than the catalyst used with gasoline-fueled engine exhaust, and (2) the exhaust from methanol combustion has a lower exhaust-gas temperature and a lower heat of reaction in the catalyst bed, thus reducing the likelihood of damage to the catalyst through overheating. More significantly, there are indications that engines utilizing emerging technology that is based on the catalytic dissociation of methanol would produce significantly lower emissions of both hydrocarbons and of NO_x than present-day methanol-fueled vehicles.

Several important additional variational calculations were also made, all based on the Case A inventory. The first was an investigation of the sensitivity of the model results to possible errors in the projected mass of highway-vehicle emissions for the year 2000. Runs were made using Case B inventory data in which those emissions were 25% and 50% higher than the figures projected by the SCAQMD. The results are shown in Figure 6-1.

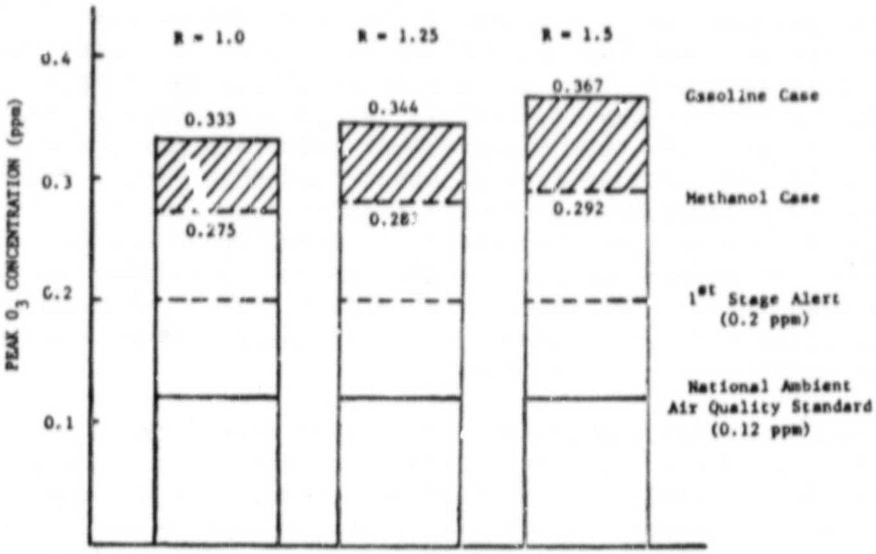
The second variational calculation was intended to establish the maximum reduction in peak ozone concentration that could be achieved by any strategy to limit emissions from gasoline-fueled vehicles in the year 2000. An emission inventory was used (based on Case A) in which those emissions were set to zero.

The last variational calculation was made in order to obtain an estimate of the effective reactivity of methanol in the atmosphere. In this calculation, the mass of methanol in the Case A inventory was set equal to zero and the peak ozone concentration was compared with that obtained for the methanol Case A calculation.

All the modeling calculations were made for the trajectory of an air parcel traversing the Basin and passing through the City of Upland at 4:00 p.m. The meteorological conditions were those which existed on June 28, 1974. On that day, air quality was particularly bad, with a peak ozone concentration of 0.38 parts per million (ppm) at 3:00 p.m. at Azusa. The trajectory was chosen because it passed through Azusa, which had the highest Basin-wide concentration of ozone on that day, and because the ozone concentration along the trajectory was relatively insensitive to initial concentrations of pollutants. Estimation of those initial concentrations is generally subject to some uncertainty. Concentrations of the following pollutants were noted: ozone, formaldehyde, and peroxyacyl nitrates.

2. Results of Modeling Calculations

a. Ozone Concentrations. Figure 6-2 shows the peak ozone concentrations for four different cases. The results indicate that substitution of methanol for gasoline as a fuel for highway vehicles would result in



Notes:

1. Methanol was assumed to be substituted for gasoline but not for diesel.

2. Mass of exhaust emissions for methanol vehicles:

   Hydrocarbons: same as for gasoline vehicles, NO_x: 50% lower than for gasoline vehicles.

3. $R = \text{Ratio} \; \dfrac{\text{Actual Highway Vehicle Emissions in Year 2000}}{\text{SCAQMD-Projected Highway Vehicle Emissions in Year 2000}}$

Figure 6-1. SENSITIVITY OF OZONE PEAK TO PROJECTED EMISSIONS FOR HIGHWAY VEHICLES IN THE YEAR 2000

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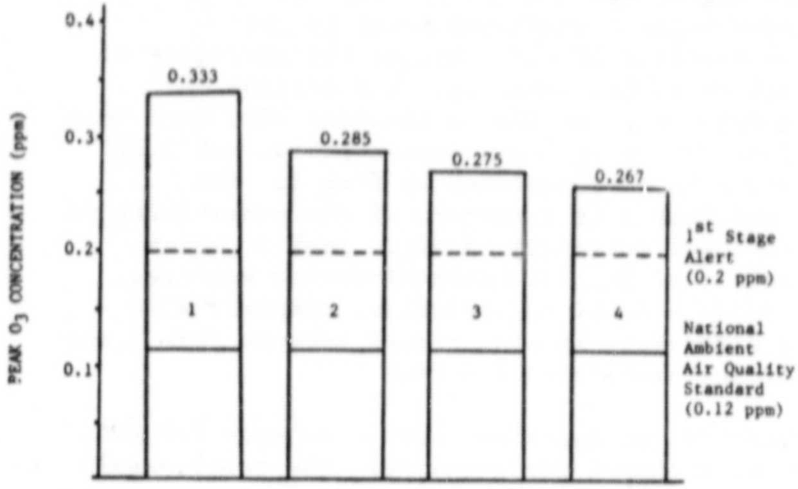

Legend

1. Based on SCAQMD Projection of Emissions for Year 2000.
2. Complete Substitution of Methanol for Gasoline, Based on SCAQMD Projection of Emissions for Year 2000.
3. Complete Substitution of Methanol for Gasoline, Based on SCAQMD Projection of Emissions for Year 2000, with Methanol Vehicles Having 50% of NO_x Emissions of Gasoline Vehicles.
4. Complete Substitution of Methanol for Gasoline, Based on SCAQMD Projection of Emissions for Year 2000, with Methanol Vehicles Having 50% of NO_x and HC Emissions of Gasoline Vehicles.

Figure 6-2. PEAK OZONE CONCENTRATIONS FOR VARIOUS EMISSION LEVELS

substantial reductions in levels of ozone and peroxyacyl nitrates. The four peaks, shown in Figure 6-3 (see p. 6-9), are as follows:

Peak 1. The daily maximum ozone concentration for the base case in which gasoline is used as the fuel for all the conventional, spark-ignited-engine vehicles in the South Coast Air Basin in the year 2000. The vehicle emissions for the year 2000 were estimated by the South Coast Air Quality Management District and published the Air Quality Management Plan. The peak level of ozone was 0.333 ppm and the peak level of PAN was 0.033 ppm.

Peak 2. The ozone concentration for the Case A methanol inventory in which there is complete substitution of methanol for gasoline in the year 2000, with total emissions of reactive organic compounds and of oxides of nitrogen from methanol-fueled vehicles being equal to the corresponding emissions for gasoline-fueled vehicles. Please note that this assumption is very conservative. Projections by SCAQMD for gasoline-fueled-vehicle emissions in the year 2000 were used in this modeling calculation. The peak ozone concentration was 0.285 ppm, which

is 14.4% lower than the corresponding peak for the gasoline case shown in Peak 1. In addition, the peak concentration of PAN was reduced by 21.5%.

Peak 3. Ozone concentration for the basic Case B methanol inventory, assuming complete substitution of methanol for gasoline for all conventional, spark-ignited-engine vehicles in the year 2000, with total exhaust emissions of reactive organic compounds equal to the corresponding emissions for gasoline-fueled vehicles but emissions of NO_x 50% lower than for gasoline-fueled vehicles. Projections by SCAQMD for gasoline-fueled-vehicle emissions in the year 2000 were used in this modeling calculation. The peak ozone concentration was 0.275 ppm, 17.4% lower than the base case represented by Peak 1. The difference between Peak 2 and Peak 3 is a measure of the sensitivity of peak ozone concentration to total emissions of NO_x. Peak 3, which allowed for 50% lower emissions of NO_x for methanol-fueled vehicles, represented a decrease of 8.5% in total NO_x emissions compared with Peak 2. The corresponding difference in peak ozones between Peak 2 and Peak 3 was equal to 3.5% of the peak value for Peak 2.

In the Case B methanol inventory, calculations were also made for 20%, 50%, and 100% substitution of methanol for gasoline. The relationship between peak ozone concentration and percentage of fuel substitution is shown in Figure 6-4. The reduction in peak ozone concentration relative to the base case was 6.6% for 20% methanol substitution and 9.9% for 50% methanol substitution.

Peak 4. Obtained for the methanol inventory Case C, which is complete substitution of methanol for gasoline, assuming that total exhaust emissions of both NO_x and reactive organic compounds are 50% lower than the corresponding emissions for gasoline-fueled vehicles. Projections by SCAQMD for gasoline-fueled-vehicle emissions in the year 2000 were used in this modeling calculation. The peak level of ozone was 19.6% lower than the base level of Peak 1.

Figure 6-1 (see p. 6-5) shows results of calculations to investigate the possible effect on peak ozone level of possible errors in the estimation of motor-vehicle emissions for the year 2000. Note that, while the absolute values of peak ozone concentrations do change, the percentage reduction in peak ozone as a result of methanol substitution is not particularly sensitive to changes in the mass of highway emissions.

When the mass of methanol emissions in Case A are set equal to zero, the resulting peak ozone concentration is 16.4% lower than that of the AQMP base case. By comparison, the peak ozone concentration corresponding to the Case A inventory was 14.4% lower than that for the AQMP base case. Thus, as was expected, it was found that the reactivity of methanol was relatively low.

Obviously, the assumption of complete substitution of methanol for gasoline is quite unrealistic and was made only for convenience, in order to establish limits. Calculations for more realistic percentages of substitution of methanol for gasoline, as shown in Figure 6-3, indicate that the peak ozone concentration decreased approximately linearly with percentage of substitution.

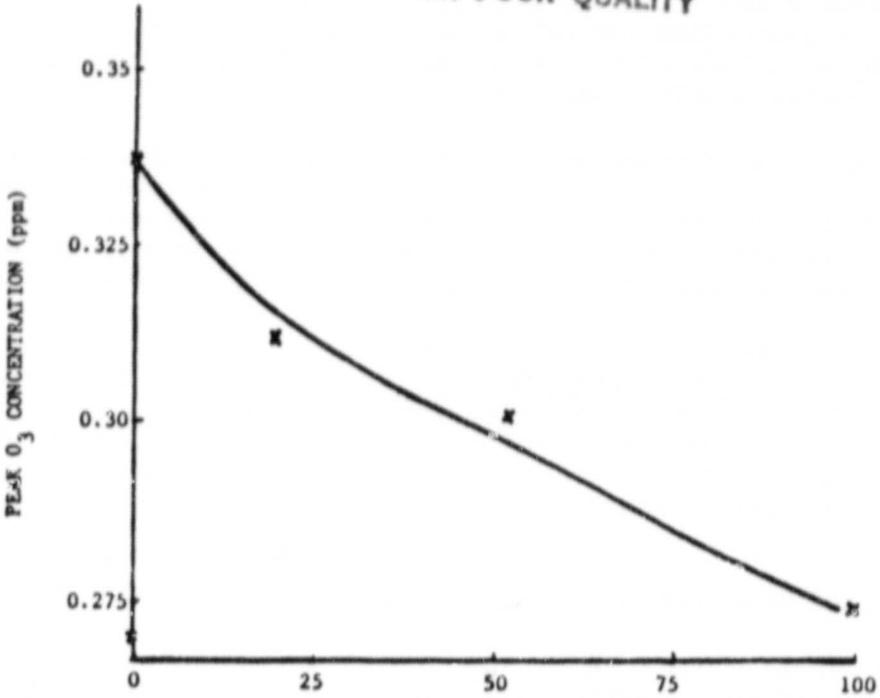

Figure 6-3. PLOT OF PEAK OZONE CONCENTRATION VERSUS PERCENTAGE OF HIGHWAY VEHICLES USING METHANOL

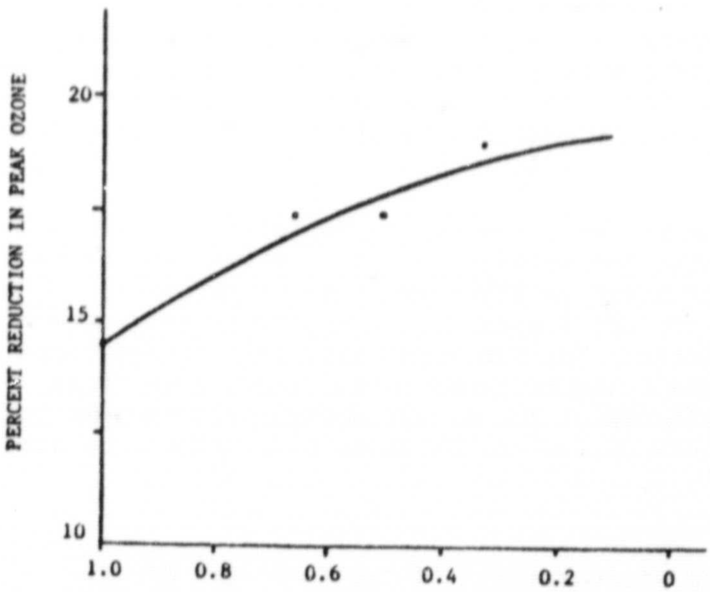

Figure 6-4. REDUCTION IN PEAK OZONE AS A FUNCTION OF NO_x EMISSIONS FOR METHANOL VEHICLES

Also investigated was the effect of methanol-vehicle NO_x emissions on ozone concentration. The results are shown in Figure 6-4, where the percent reduction in peak ozone concentration is plotted against the assumed average mass of NO_x emissions from methanol-fueled vehicles, expressed as a fraction of the projected gasoline-vehicle emissions.

Finally, all exhaust and evaporative emissions from gasoline-fueled vehicles were set equal to zero in order to establish the maximum reduction in peak ozone concentration that could be achieved by any strategy to limit emissions from gasoline-fueled vehicles in the year 2000. By comparison with the base case, the reduction in peak ozone concentration was found to be 25%.

b. Formaldehyde Concentrations. The air-quality model was used to predict hourly average concentrations of formaldehyde along the trajectory. The peak hourly concentration of formaldehyde for a typical smoggy day was 0.0355 ppm for the base case and 0.0535 ppm for the methanol case. These concentrations are not high enough to justify general concern.

C. ESTIMATION OF IMPACT ON SULFUR COMPOUNDS AND PARTICULATES

The likely changes in the ambient concentrations of sulfur compounds as a result of methanol substitution were estimated for the year 2000. Because of the very high level of uncertainty in the projected inventory of emissions for total suspended particulates, that projected inventory was not used for any calculations.

The suspended particulates include sand, dust, non-volatile carbon (soot), sulfates, inorganic nitrates, organic nitrates, and condensible organic substances. Thus the term total suspended particulates (TSP) is a blanket description for a variety of chemical species in a range of particle sizes, and reveals little about the impacts that those different kinds of particulates would have on the environment. For this reason, emission inventories for TSP were not used in assessing the possible impact of methanol. Instead, a qualitative evaluation was made based on some published work.

According to Cass, Boone, and Macias,[36] on-road and off-road diesel engines accounted for 61.0% of all fine non-volatile carbon emissions in the South Coast Air Basin in 1980, while gasoline-fueled vehicles accounted for 10.2%. Methanol-fueled engines, on the other hand, produce very little particulate matter. The Southern California Edison Company performed combustion tests using methanol in boilers and turbines, from which they confirmed that methanol was an extremely clean-burning fuel. Pefley and his associates at the University of Santa Clara have made similar observations

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[36]See Reference 46, Chapter 6 of the Technical Report.

from their work with methanol-fueled, spark-ignited engines. Thus, if methanol were to be substituted for gasoline, there would be a reduction in total emissions of non-volatile carbon. A much larger reduction in such emissions would occur if methanol were to be substituted for diesel fuel as well as gasoline.

The expected ambient concentrations of SO_x and sulfates were estimated relative to their ambient concentrations for 1979 using the "linear roll-back" approximation. That approximation assumes that the change in ambient concentrations between 1979 and the year 2000 is directly proportional to the change in the total emissions of the corresponding primary pollutants over the same period. No more sophisticated methods of calculation are available for the sulfur compounds.

Emissions of sulfur oxides were projected for the year 2000 for three cases, two of which were described earlier in this section:

(1) SCAQMD Base Case.
(2) Methanol Case A.
(3) Methanol Case E.

The methanol Case E was similar to Case A except that for Case E all utility boilers and industrial and other boilers were also assumed to be converted to methanol fuel.

D. FINDINGS

The conclusions drawn from the air-quality modeling calculations and from the semi-quantitative analysis applied to projected emissions of sulfur are summarized below. The comments apply to the complete substitution of methanol for gasoline in the South Coast Air Basin, based on projected emissions for the year 2000. Even though this is not a feasible scenario for methanol use, the intent was to bound the air-quality implications of substituting methanol for gasoline and to calculate a limiting case. Therefore:

(1) The complete substitution of methanol-fueled vehicles for gasoline-fueled vehicles would lead to a reduction of 14.4% to 20.0% in the peak hourly-average concentration of ozone.

(2) The peak ozone concentration decreases approximately linearly with methanol substitution.

(3) Even with a very optimistic rate of neat methanol vehicle adoption, the maximum impact by the year 2000 would be only a 3% to 4% reduction in the peak hourly average concentration of ozone.

(4) The photochemical reactivity of methanol is relatively low. Thus when the mass of emissions of methanol in Case A was arbitrarily set to zero, the peak ozone concentration was reduced by only 2.3%.

(5) With the use of methanol fuel, the peak ozone concentration is reduced as emissions of NO_x are reduced. The ozone concentra-

tion, however, is a lot less sensitive to emissions of NO_x than to reactive organic emissions.

(6) The maximum reduction in ozone concentration achievable by elimination of gasoline-fueled-vehicle emissions is 25%.

(7) With methanol substitution, the ambient concentration of formaldehyde would not increase significantly.

(8) The concentration of sulfur-derived pollutants would not be significantly affected by methanol substitution. If methanol were to be used in utility boilers and in industrial and commercial boilers, there would be a large reduction in the concentration of sulfur-derived pollutants.

(9) Total suspended particulates in general would not be greatly affected by methanol substitution. The concentration of fine, non-volatile carbonaceous particulates, however, would be reduced slightly if methanol were substituted for gasoline. If methanol was also to be substituted for diesel fuel, the reduction in the concentration of non-volatile carbonaceous particulates would be much larger.

The approximate linear relationship, Conclusion (2), between the degree of methanol substitution and the peak concentration of ozone implies that the atmospheric reactions of methanol and those of the reactive components and byproducts of gasoline are not significantly coupled. That observation is entirely consistent with the fact, indicated in Conclusion (3), that methanol is significantly less reactive than the other reactive compounds in the atmosphere.

Conclusion 4 appears, superficially, to be at variance with the results of a recent study made by System Applications, Inc. (SAI) of San Rafael, California, on behalf of the Western Oil and Gas Association (WOGA). Actually, the SAI/WOGA study was based on different premises than those used in the calculations described in this section. The results[37] refer to the case where methanol was substituted for gasoline, which was not one of the cases considered by the SAI/WOGA study. The SAI/WOGA study used a different emission inventory than that used in this study; they used a projected 1987 inventory and applied to it the emission reductions expected from implementaton of some provisions of the Air Quality Management Plan for the South Coast Air Basin. There may also be other differences in the data used in the modeling calculations. Therefore, Conclusion (4) does not necessarily contradict the results of the SAI/WOGA study.

Table 6-2 summarizes the expected physical effects upon the atmosphere of a large-scale substitution of methanol for gasoline. The table is only qualitative, and is intended to give a very general overview of the effects of

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[37]See Figure 6-6 of the Technical Report.

Table 6-2. CHANGES IN AIR QUALITY DUE TO USE OF METHANOL IN SPARK-IGNITED MOTOR VEHICLES IN THE SOUTH COAST AIR BASIN IN THE YEAR 2000

POLLUTANT	CHANGE	PHYSICAL IMPACTS
OZONE	Reduction	-Reduced acute respiratory illness -Reduced damage to paints, elastomers, rubber -Reduced damage to crops
SULFATE	Small reduction	-Reduced mortality -Reduced acidity of rain -Improved visibility
FORMALDEHYDE	Small increase	-Possible odor -Eye irritation if local concn. high -No known health effects at low concn.
NITROGEN DIOXIDE	Small reduction	-Reduced acidity of rain -Possible reduction in respiratory illness
ORGANIC NITRATES	Significant reduction	-Reduced eye irritation
TOTAL SUSPENDED PARTICULATES	Reduction	-Improved visibility

different air pollutants. The sources of information about the physical effects of the pollutants are listed in Table 6-22 of the Technical Report.

E. CONCLUSIONS AND DISCUSSION

The work described in this section is only an initial investigation. The accuracy of the data used in the modeling calculations could possibly be improved. However, the overall conclusions are believed to be substantially correct. Generally, very conservative assumptions were used in the analysis.

The emerging technology for the catalytic dissociation of methanol using exhaust heat from the vehicle's engine has the potential for significant reductions in motor vehicle emissions. Hard data of emissions from dissociated methanol vehicles must be obtained so that the likely impact of such vehicles on the environment may be evaluated.

The study results clearly indicate that the impact of methanol on the South Coast Air Basin atmosphere would be beneficial. For some pollutants,

the potential improvements are significant. The most significant impact would be in reducing the peak level of ozone, but only if a major portion of vehicles in use were methanol-fueled. Even a small reduction in peak level would cause larger reductions in the number of days on which smog episodes occur, and thereby cause an improvement in the air quality for the residents of the Basin. Obviously, the use of methanol is no panacea for the problems of air pollution. Other pollution-abatement measures would still be needed. If neat methanol-fueled passenger cars were to become over-the-road competitive with gasoline vehicles in 1990, and from that point achieve a rate of sales consistent with the rate of adoption for diesel-fueled vehicles since 1978, the vehicle stock would be about 12% neat methanol-fueled vehicles by the year 2000. With 12% of the vehicles fueled with neat methanol the impact on peak ozone would be to reduce it approximately 3.7% from the base case. Obviously, neat methanol-fueled vehicles could be adopted either more rapidly or more slowly than diesels, which would change this year-2000 impact, but it is unlikely that the change could be too large given that neat methanol will not be competitive over the road for at least 8 years, and creating a distribution system widespread enough to attract a broad-based market will take a good deal of time. From both the perspectives of over-the-road cost-effectiveness and depth of distribution outlets, methanol will not compare favorably with diesels before their rise in percentage of new vehicle fleet sales. Thus, although the analogy with diesels is weak, neat methanol has more barriers to overcome, which will make its rate of adoption tend to be less, if anything, than the diesel experience since 1978. As a result, the 3.7% impact on peak ozone by 2000 for neat methanol vehicles is probably optimistic and, in any case, only a modest factor in that timeframe.

In this report, there has been no attempt to quantify the economic value of the likely air-quality benefits of methanol as a fuel in the South Coast Air Basin. It was simply assumed that the use of methanol will be determined by the free market, depending on the price and the utilization of efficiency of the fuel. There is a brief discussion in the Summary Report (page 7-9) of possible mechanisms by which the use of cleaner fuels could be encouraged.

The main conclusion from this analysis is that the use of methanol in motor vehicles could form part of an effective long-term strategy to reduce air pollution in the South Coast Air Basin.

SECTION VII

ROLES OF THE PUBLIC AND PRIVATE SECTORS

A. INTRODUCTION

From California's perspective, there are two overriding motivations for examining methanol as an alternative fuel in stationary and transportation applications: security of supply and environmental improvement. However, both these factors may not be sufficient to induce methanol implementation if they are not deemed to be of sufficient value to make methanol viable in specific applications. The intent is to see if there is justification for government intervention in the private marketplace to either facilitate or accelerate methanol production and use. In other words, given that the description in Section V is a reasonable projection of what the mid-term consequences would be of letting the market determine methanol introduction and evolution, the goal here is to determine, based on the data developed in the study and other sources, whether a government role is justified and, if so, what the likely impact of government policy would be on the methanol fuel market. In other words, the intent is to take the transition period case as discussed in Section V, and determine if justifiable State policy can significantly change the outlook for methanol in the next fifteen years. The impact of State policy is then shown at the end of this section as the "derived likely roles" which methanol can have in California if the state implements policies to eliminate externalities and other impediments to methanol use. Thus, by definition the difference between the "business as usual" case in Section V and the "derived likely roles" for methanol is State policy. The policies considered in the section are only those which deal with imperfections in the market process and are justified in terms of net benefits to the State of California. There are, of course, more aggressive policies which heavily subsidize methanol production or use and could possibly result in faster market penetration, but a compelling rationale for policies of this type has not been found in this analysis or other studies.

In areas where there is simply too much uncertainty to formulate a policy for methanol use in the state, the objective is to evaluate whether the pre-conditions exist in terms of efficient markets and other institutional mechanisms for the expansion of methanol fuel use if it meets the market test. Emphasis is placed on examining mechanisms that help the market reflect the cost and benefits of methanol as they become known and that efficiently transmit them to both potential producers and consumers.

B. TRANSPORTATION FUEL SECURITY

The rapid changes in events and trends in the last decade are an indication that our understanding is quite limited of how energy markets in general and international oil markets in particular will evolve. During the last 8 years since 1974, the forecasts of energy demand have changed dramatically in response to a better understanding of supply and demand elasticities, Middle East politics, and our own evolving policy. It has been previously shown how the forecasts from one consistent source have changed with time (see Figure 3-1).

The most recent forecast, available in the summer of 1982,[38] continues this downward trend, but at a smaller rate of change. In the recent forecast, a year-2000 energy forecast is for 95 quads compared to a 101-quad forecast in early 1981. The main point is that we as a nation are still learning what the impact on energy use can be in response to both institutional, technical and international political changes.

1. OPEC in the 1980s

In the months following OPEC's meeting in March 1982, the trend in the international oil market changed significantly from disunity to Saudi Arabia re-establishing its leadership through OPEC policy. The formulation of a production allocation policy was important because it was the first time that OPEC had imposed production quotas since their rise in the 1970s to world prominence. In addition, it is in the setting and enforcing of production quotas that cartels have often disintegrated in the past. During the 3 months following their special session, the oil markets signaled that their policy was basically successful. Spot prices of crudes rose enough to offset most of the declines in early 1982, restoring them to near the official level. The apparent success of this policy was more psychological than real in the sense that it demonstrated that OPEC (or more accurately Saudi Arabia) still would set the world price of oil. Market conditions would tend to erode the official price over time in real terms, but expectations of a collapse were greatly reduced.

More recently, OPEC's meeting in late June ended on a much less conclusive note. Saudi Arabia did not attend on the basis of observing religious holidays and in its absence the cartel failed to reach agreement on production quotas. Iran, in particular, is in no mood to be cooperative after their victory over Iraq. The support which Saudi Arabia and others gave to Iraq, and the production quota given to Iran of slightly over 1 million barrels per day (MMBD) is viewed by Iran as perhaps a factor of three too low. The ultimate result of this situation is obviously highly uncertain. Saudi Arabia could voluntarily absorb greater production cutbacks itself, or call another special meeting and achieve another compromise victory on OPEC pricing/production. Although these recent events are interesting as a guide to OPEC's evolving role in world oil markets, the interest for this study is in the longer term, when methanol could have a significant impact on transportation fuel markets in California.

Events since 1979 in world oil markets and prospects for the future indicate that OPEC cannot set prices at arbitrarily high levels. The price increase in 1979, on top of 1974 increases, was too high to be sustained when long-run adjustments in demand materialized. The demand and supply of oil in the short run is quite inelastic. More efficient utilization technology turns over every 10-12 years for automobiles, 20 years for home heating systems, 40-50 years for residential and commercial buildings, and 25-30 years for

[38]Data Resources, Inc., Energy Review, Vol. 6, No. 2, Summer 1982.

utility and industrial boilers.[39] Obviously, with such a long turnover period, the ability for quick response simply does not exist. On the production side of the fuel market, new projects in oil, gas, synfuels, pipelines, etc., all take 8 years or longer to impact the market. Thus, although short-term elasticities are extremely low, the long-term response on the demand side can be substantial. The significance of these market realities is probably quite evident to Saudi Arabia; the country will continue to be a moderating force (for its own self interest in the long run) on OPEC pricing behavior. Real prices should continue below 1981 levels until at least 1985, barring any political disruption in oil flow, and then start to grow in real terms in response to economic growth and the end of the worldwide recession. An orderly world market would not pose as great a difficulty for energy planners, even with some real price increases and numerous political interruptions. Although industry can deal with evolving changes in supply/ demand balance, the prospect of political disruption is a public concern as well.

2. Supply Disruptions

Although the recent reductions in oil prices compared to 1981 levels are a welcome relief from escalating real oil prices, the potential for another sudden price increase has not vanished. If one looks for significant factors in OPEC policy, two stand out:

(1) Politically caused disruptions have allowed OPEC to raise prices.

(2) Saudi Arabia has moderated extreme market conditions through its production decisons.

Looking at the future in terms of disruption potential, it is clear that things have improved since 1979 in the sense that OPEC has significant excess production capacity. This change is important if a moderate-scale political disruption should occur: other OPEC members will be tempted to pick up the slack. For example, in 1982, capacity utilization should average about 61%, down from 82% in 1980, and even with economic recovery it should only grow to 76% by 1990. A result of excess capacity is that a moderate producer (e.g., Iraq, Libya) could totally cease export as a result of some political problem and the world market could absorb the loss without a major price increase. Thus, the causes of a potential disruption that could lead to major price increases in the 1980s have been narrowed. Where the loss of any significant producer would have sent oil prices escalating in a period of little excess capacity, now it would require a major producer to be lost (Saudi Arabia or two or more of the lesser producers). Thus, the possible set of events which could set off rapid price increases has been narrowed.

In spite of this relative improvement in our position in world oil markets (both the import reduction to under 5 MMBD and the excess production capacity in OPEC), the United States and the countries forming the Organization for Economic Cooperation and Development (OECD) are still extremely vunerable

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[39]Data Resources Inc., Energy Review, Vol. 6, No. 2, p. 2, Summer 1982.

to a large disruption. In addition, three sets of events currently evolving make the threat of a very large disruption as likely as at any time in the last few years. First, Iran's victory over Iraq to reclaim its own territory may only be a stepping stone to broader scale adventurism in the Middle East. An invasion into Iraq, or an attack on Kuwait or Saudi oil installations is possible as retribution for support of Iraq during the recent war. The second factor that is potentially destabilizing is the softness of world oil markets and the potential for OPEC losing control of setting world oil prices. It is a case of too fast a fall in world oil prices (to perhaps $25/bbl) putting tremendous pressure on the development plans of some OPEC members. Some would even face severe internal turmoil without large oil revenues. Under such circumstances, the destabilizing forces could create internal OPEC conflicts that could result in lost oil production capacity. Finally, the current situation in Lebanon, although not directly affecting oil producers at this time, certainly has the potential for involving other Middle East nations. Thus, although the set of threats that could trigger another precipitous world oil price increase have narrowed, a few specific ones have intensified.

3. Import Premiums

There are two general classes of policies that can be used to prepare for import disruptions. One has to do with defining procedures for whether market forces or allocation programs will be used, or whether reserves will be established and how large they should be for dealing with actual disruptions. Such issues, although important, are not directly pertinent to methanol's role as a synfuel that could provide diversity and security in case a severe oil disruption should occur.

A concept which is useful in this context is: What is the value of the import premium[40] for assessing the value of alternative import reduction programs? A report has been recently published on this subject by the Energy Modeling Forum (EMF) at Stanford University that gives a thoughtful evaluation of this concept.[41] The basis for calculating a premium for reductions in oil imports is that programs established to reduce impacts in advance pay off in a number of ways:

(1) Market power component: a reduction in imports would tend to reduce the price for all oil imported.

(2) Security component: import reductions may create excess capacity in OPEC producers that will moderate disruption effects and also reduce the quantity of oil exposed to escalation and hence its economic ramifications on the economy.

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[40] Defined as the economic benefits of oil import reduction on a per barrel basis.

[41] Energy Modeling Forum, World Oil, Stanford University, Stanford, Calif., EMF Report 6, February 1982.

The Energy Modeling Forum acknowledges the difficulty of making these estimates and has used ten world oil market models in an attempt to represent a diverse set of assumptions and approaches. Even so, none of the existing models deal comprehensively with such problems as inventory-holding policies of consumers, utilization of excess capacity by OPEC producers, and feedback of oil price increases into general economic activity. Thus, no claim is made that the estimates are precise, but rather they are given as a rough guide to the range of estimates that are reasonable under different assumptions. The import premium estimates from the EMF report are summarized in Table 7-1 for both the United States alone and the OECD as a group.

The key assumptions that drive these results are that the probability of a disruption occuring in a given year is 5% for a 10-MMBD, 1-year duration interruption. Increases in the probability of a disruption occuring or the length of its effects would increase the security component of the import premium. In general, the results indicate that world oil prices can be reduced from $0.90 to $2.40 per barrel for each MMBD import reduction, in 1981 dollars. Thus, a simple approximation to the market power component for the United States is derived by multiplying the price reduction times the quantity of oil still imported. For example, a reduction in imports from 5 MMBD to 4.5 MMBD would have a market power component of between $4.05 and $10.80 per barrel.[42] The security component estimates range from $1 to $5 per barrel for the United States and from $4 to $17 per barrel for the OECD.

Table 7-1. EMF IMPORT PREMIUM ESTIMATES
(1981$/barrel)

MODEL	U.S. PREMIUM MARKET POWER	U.S. PREMIUM SECURITY	U.S. PREMIUM TOTAL	OECD PREMIUM MARKET POWER	OECD PREMIUM SECURITY	OECD PREMIUM TOTAL
Gately	10	-	10+	35	-	35+
IEES-OMS	9	1	10	31	4	35
IPE	8	-	8+	23	-	23+
Salant-ICF	8	0	8	27	0	27
ETA-MACRO	13	5	18	45	17	62
WOIL	7	4	11	24	14	37
Kennedy-Nehring	8	2	10	30	6	35
OILTANK	8	2	10	28	8	36
OILMAR	15	3	18	50	11	61

[42]Derived by: 4.5 MMBD x $0.90/bbl/MMBD and 4.5 MMBD x $2.40/bbl/MMBD.

It is important to clarify the meaning of these results to policy makers in the context of this study. First, given the assumptions in the EMF study:

(1) Policies that reduce imports at costs less than $8 bbl in 1981 dollars are probably economically beneficial to the United States.

(2) Policies that reduce imports at a cost of greater than $20/bbl in 1981 dollars above the world oil price will probably cause a net economic loss to the United States, while those in between cannot be evaluated given current data.

(3) Some import reduction policies that go beyond free market import levels appear to be economically justified.

(4) The import premiums discussed above do not necessarily justify any policy that cuts imports less than $8/bbl; it is still important to search for the most efficient solutions and implementation mechanisms.

In addition to the above conclusions, this study offers a few of its own on the relevance of the import premium concept to the California Methanol Assessment:

(1) The size of the economic entity (i.e., OECD, United States, California) has a profound impact on the value of the import premium to its residents.

(2) Behavior of other importers has a very significant impact on the value of an import reduction program in the state or country implementing a specific program or policy. As its import reduction/substitution has an increasing marginal cost, it would be less efficient to implement a given target reduction on a relatively smaller set of users (California) than on a national set of users (United States) or, even better, on an international user community (OECD).

(3) The key to implementing a policy of this nature is that it needs to be neutral among technologies and other options to be truely effective. Thus, implementing an import premium, such as a tariff on oil imports, is more efficient than subsidizing any particular synfuel option because it does not bias the selection process.

It is easy enough to calculate the implied value of the premium on the supply price of gasoline and thus to see if it makes a significant difference on the timetable of methanol competitiveness. Based on a recent study, the implied prices of gasoline at the pump are shown in Table 7-2 for the bounding import premium cases of $8/bbl and $20/bbl for the United States.

For this first-order comparison, the implication is that if methanol as a transport fuel were competitive with gasoline at $1.74 in 1990, there would be reason to believe that a national policy of imposing an import premium (for instance through a tariff) would induce a methanol market. If methanol re-

Table 7-2. GASOLINE PRICES WITH THE U.S. IMPORT PREMIUM

YEAR	BASELINE GASOLINE MARKET PRICE	GASOLINE WITH IMPORT PREMIUM $8/bbl	GASOLINE WITH IMPORT PREMIUM $20/bbl
1990	$1.55	1.74	2.03
1995	1.80	1.99	2.28

quired a gasoline price above $2.03 per gallon in 1990 (in 1981 dollars) to be competitive, it would be less likely to be justified on these grounds. The study analysis indicates that an increase in gasoline prices of $0.19/gallon (in 1981 dollars) does significantly accelerate the period at which methanol becomes a viable transport fuel (by about 4 years).

The conclusions of this study on the issue of national security are that: (1) there is a significant value (at least $8/bbl) above the free market oil price to oil import reduction in the United States, (2) any attempt to implement such a policy should be done at the national level, where the costs are spread among all beneficiaries, (3) an oil import premium should be implemented in a neutral manner (e.g., oil import tariff) to allow the market to select the best alternatives, (4) an import premium of $8/bbl would raise the retail price of gasoline about $0.19/gal, which would accelerate the over-the-road competitiveness of methanol and other synfuels 4 to 5 years if the premium were believed to be of a stable duration, and (5) from a fuel security viewpoint, methanol is not significantly different from other synfuels that substitute for imported oil.

Within California, the value which can be justified for an oil import premium is smaller because the market power component (impact of substitution on lowering the world oil price) is reduced considerably compared to the nation as a whole, as most of the benefits would accrue to others. The security component as estimated by the EMF had a median value of $2/bbl[43] for the United States with a disruption probability of 5% in a given year. Acting on its own, however, California would only capture a small portion of the synfuel benefits if a disruption would actually occur. Although it would require a detailed modeling analysis of California's economy in a disruption both with and without a premium (established well in advance) to measure the value of such a program, a crude estimate is provided by California's share of U.S. oil consumption. As California consumes approximately 5% of U.S. oil, the corresponding value of a premium for California only would be very small, on the order of $0.50/bbl. Even if this crude estimate is low by a factor of four (e.g., the California security premium equaled that of the United States as a whole), the conclusion is still that the premium that California could

[43]$1 to $5 per barrel range for the United States.

justify for encouraging oil substitution is very low on a cost/benefit basis. For example, a premium in the range of \$0.50 to \$2.00/bbl on imported crude oil would add only approximately \$0.01 to \$0.03/gal to the value of methanol used in neat methanol-fueled vehicles.

The security value of methanol must also be considered from the production side of the market. In the near term (i.e., through 1992), the most likely source of methanol for California is remote natural gas from the Pacific rim, Canada, and Mexico. These sources, although involving imports, are not subject to the same level of risk of disruption as is oil from the Middle East. The key issue is freedom from the likelihood of interruption of supplies from individual sources, rather than whether the source is imported or domestic. In this case, a diversified supply of methanol from Canada, Mexico, Indonesia, etc., would not place California in a particulary vulnerable position. This conclusion is especially true for the limited guarantees of methanol (relative to transportation fuel consumption) that would be obtained from these sources. It would be difficult, for instance, to justify any security premium for methanol made from Middle Eastern gas because the instability of the region would pose the same threats to methanol imports as it does to oil imports.

In the long run, the use of coal as a feedstock for methanol would make it as secure as any source of fuel supply available to California. Other possible sources for methanol (biomass and petroleum coke feedstocks) are also domestic sources and hence secure supplies for California. Thus, from a security viewpoint, there does not seem to be a major problem in any of the sources that might evolve in the remainder of this decade. One possible problem for California would be in the event that Europe does become a major consumer of Middle East methanol from remote natural gas. Even in the event that California obtained its methanol from Pacific rim sources, competition for methanol if there were a Middle East disruption would drive up prices much the same as it would for oil. Thus, remote natural gas must be considered as an intermediate step in methanol use as a transportation fuel, which in modest quantities can help the state transition to coal-based methanol use. Its security value in this transition period, however, would tend to diminish as worldwide methanol fuel demand expands and the Middle East increases its relative share of the worldwide supply.

C. ENVIRONMENTAL VALUE OF METHANOL

Another nationwide concern with special significance for California is the air quality problem in its urban centers. In this regard, methanol does have unique properties compared to other transportation synfuels, such as shale oil, Fischer-Tropsch liquids, and products of direct coal liquefaction, as well as conventional gasoline and diesel fuel. It is also clear that substitution of methanol for oil in utility applications can lead to some benefits as a result of reductions in NO_x, SO_x, and particulate emissions. The value of these benefits to the utilities, however, is not as clear.

1. Policies and Regulations

Utilities in the South Coast Air Basin (Los Angeles and vicinity) and in the Ventura Country Air Pollution Control District (particularly SCE and LADWP) are required to reduce their NO_x emissions by 60% by the year 1990. Use of methanol in some units could be included as part of an overall strategy to satisfy this requirement. This could lead to payment of a premium for methanol.

A similar requirement is under consideration to limit SO_x emissions in the South Coast Air Basin, and there may be requirements to reduce particulate emissions; but the value of methanol use as an emission control strategy cannot be determined until these regulations are finalized.

Methanol may also provide benefits in regard to the "offsets" and "bubble" policies currently being developed by federal, state, and local air pollution control agencies. Methanol use could provide offsets to be used for expansion of other facilities or for sale to other companies. Under the bubble policy, burning methanol in one boiler could allow less expensive higher-sulfur oil to be burned in another boiler. A recently completed study done at Caltech[44] indicates that if a market were created for tradable emission licenses for sulfur oxides, the value of a license to emit one ton per day of sulfur oxides for a year in Los Angeles would be worth $400,000 to $1.5 million, depending on whether natural gas were available. These types of policies are in their infancy, and there is no precedent that can be used to predict the outcome of their application here. Thus, methanol would have a premium value as part of overall strategies for NO_x and SO_x reduction, but the level of that premium depends on the level of desired environmental goals and the least expensive options for obtaining these goals.

2. Value of Environmental Benefits

As part of this study, an evaluation has been made of the environmental control technology in utilities. The results, which are specific to the Los Angeles basin, are highly dependent upon the regulations that might exist, the level of abatement desired, and the abatement alternatives available for utilities, industry, and automobile manufacturers to meet these regulations.[45] The two basic strategies evaluated for NO_x reduction are:

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[44]Cass, Hahn, and Noll, Implementing Tradable Emissions Permits for Sulfur Oxides Emissions in the South Coast Air Basin, Environmental Quality Laboratory, California Institute of Technology, June 30, 1982.

[45]Using specific control technologies would tend to overstate the cost of abatement compared to an airshed tradable-emission permit program in the South Coast Air Basin, which would encourage each polluter to search for the least costly abatement options. An attempt has been made, however, to examine abatement alternatives and to pick the most efficient option (least costly) that meets the desired abatement target. In the long run, a tradable license program may be established which would permit the use of market-determined premiums for clean fuels.

(1) selective catalytic reduction for oil-fired boilers, or (2) a combination of selective catalytic reduction in a limited number of plants and low NO_x burners in others. These abatement technologies were compared with the costs of different ways to use methanol for emissions reduction, including: (1) complete methanol substitution for other fuels, (2) 30% dual-fueling, (3) 15% dual-fueling, and (4) repowering. The results, shown in Table 7-3, show the value of methanol in NO_x reduction compared to the least costly alternative examined for three levels of decrement in required NO_x output.

As indicated in Table 7-3, the base case premium is zero, which means that there is currently a plan for complying with NO_x reduction requirements in the South Coast Air Basin. Basically, the plan calls for using natural gas, expanding San Onofre, and adding geothermal capacity to avoid using oil in existing boilers within the Basin. If any of these elements of the plan are not met and oil does need to be used in these boilers, some form of emission control equipment (e.g., selective catalytic reduction or low NO_x burners) would have to be added to the oil-fired units to meet the NO_x standards. Using this approach, the premiums derived for the case where no natural gas is available are highest for using 15% methanol in an overfiring mode with residual oil. The premium is $\$0.30/10^6$ Btu in this type of application. The potential premiums are largest if a more severe change in the plan occurs (i.e., San Onofre is not available for use) that imposes the

Table 7-3. PREMIUM VALUE OF METHANOL IN NO_x REDUCTION IN UTILITIES ($\$/10^6$ Btu)

METHANOL OPTIONS[a]	BASE CASE[b]	DEVIATIONS FROM BASE CASE		
		NO GAS AVAILABLE	GEOTHERMAL GENERATION NOT AVAILABLE	SAN ONOFRE NOT AVAILABLE
Methanol Fueling	0	0.10	0.10	0.50
30% Dual-Methanol Fueling	0	0.20	0.20	1.10
15% Dual-Methanol Fueling	0	0.30	0.25	0
Repowering	0	0.10	0.10	0.60

[a]A more detailed discussion of methanol options for reducing NO_x can be found on pages 9-52 to 9-57 of the Technical Report.

[b]SCE currently has an approved plan for complying with NO_x restrictions; thus, if the plan is fully implemented, there is no premium justified for further reductions. Three deviations from the plan were considered: that no natural gas is available, that geothermal capacity is not constructed, and that San Onofre is not available for use.

need to operate the oil-fired capacity much more intensively. In this case, the premium is still highest for overfiring with methanol, but with a value of $\$1.10/10^6$ Btu over the cost of natural gas. It is important to stress, however, that the base case premium is zero and the most likely deviations from the plan (no gas available or geothermal capacity not completed) lead to premiums of $\$0.25$ to $\$0.30/10^6$ Btu.[46] There may be less expensive and thus more efficient ways to reduce NO_x output, either by utilities or other sources of NO_x, which could be induced by a market-oriented incentive program (e.g., tradable licenses). This issue needs to be studied further so that the incentives or premiums for clean-burning fuels like methanol can be determined by the least costly mechanisms to achieve any target emission level. A reasonable bound on the premium value of methanol in NO_x reduction, however, is from zero to $\$0.30/10^6$ for the NO_x standards and control options expected in the near future. Furthermore, if the no-gas-available case were to arise, the quantity of methanol involved would be approximately 3000 ton/day, which would receive the $\$0.30/10^6$ Btu premium over natural gas or 0.25% sulfur oil.

An estimate has also been made of a possible value of methanol as a strategy for SO_x reduction. If a policy for reduction of 60% of SO_x were enacted in the South Coast Air Basin, one strategy would be to burn natural gas in the oil-fired utility units in the Basin. If this requirement were enacted and natural gas were not available, another strategy would be to burn 0.1% sulfur oil instead of the 0.25% sulfur oil now used. If this strategy were implemented in all the oil-burning plants in the Basin, the cost premium for this low-sulfur oil would translate into a value of $\$0.65/10^6$ Btu for methanol as an alternative. In other words, if methanol were less than $\$0.65/10^6$ Btu more expensive than 0.25% sulfur oil, it would become the most efficient abatement option.

The premiums for the values for methanol as a pollution abatement strategy would be an additive for NO_x and SO_x. Thus, the potential premium value is approximately $\$0.65$ to $\$0.90/10^6$ Btu, or about \$0.05/gal of methanol. This size premium is not likely to induce use of methanol in many plants. The cost difference that has been calculated between methanol and conventional utility fuels is much larger than this value. Nevertheless, in the longer run it would be highly desirable if a market system were established to create a stable mechanism for determining the value of the premium which methanol or other clean fuels should have as part of an efficient environmental program.

D. GOVERNMENT PRODUCTION INCENTIVES

With the highly capital-intensive nature of coal-to-methanol plants, a reduction in the required cost of capital has a major impact on production cost. As a way to illustrate this relationship, the production costs from the

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[46]There are a few special cases where plants are capacity-constrained by NO_x restrictions. In these instances, the premium for methanol could be higher if the value of the increase in capacity factor were credited to methanol.

reference case,[47] coal-to-methanol plants, have been plotted against alternative required rates-of-return (Figure 7-1).

As shown in Figure 7-1, the minimum acceptable selling price per gallon rises from \$0.56/gal to \$1.36/gal at required rates-of-return[48] of 11% and 25%, respectively. The reference case assumption is for a 20% return consistent with hurdle rates in the petroleum industry,[49] which yields a minimum acceptable selling price of \$1.00/gal. The types of guaranteed loans and price guarantees provided by the Synthetic Fuel Corporation have the effect of lowering the overall required return from 20% to approximately 13.5%

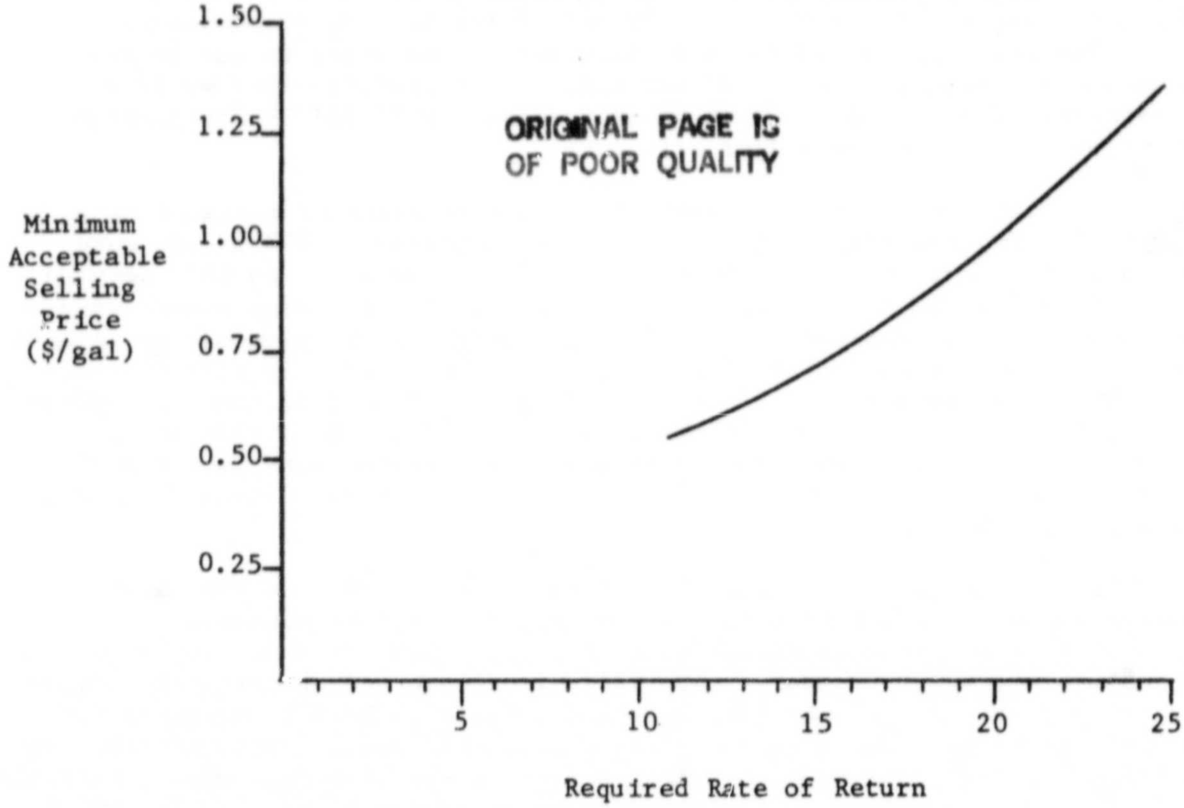

Figure 7-1. SENSITIVITY OF COAL-TO-METHANOL PRODUCTION COSTS TO REQUIRED RATES-OF-RETURN (1981\$/gal)

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[47]These cost estimates are based on a 5000-ton/day Texaco gasification plant, located at a western minemouth on-line in 1992. Other assumptions are shown in Tables 4-6 and 4-25 of the Technical Report.

[48]Rates-of-return are all expressed in nominal, after-tax terms.

[49]In discussions with sponsors of this study, a 20% nominal after-tax return was determined to be the appropriate threshold for coal-to-methanol plants, although rates as high as 25% were also suggested by some companies.

for some ventures (e.g., a 30% equity share with a 30% return and 70% debt at 13% yields a 13.55% overall return with a 50% tax rate). Thus, SFC has the capability (through its impact on the cost of capital) to lower the minimum acceptable selling price at the plant gate to $0.65 to $0.70/gas in 1981 dollars. It is also possible to further subsidize these plants by granting price supports to further reduce the minimum acceptable selling price. However, it is felt here that further subsidy may not be necessary for methanol to compete in the octane enhancement market nationally. Thus, SFC could minimize its contribution to coal-to-methanol projects by limiting its participation to loan guarantees. If methanol is to compete as a utility fuel, however, substantial price subsidies appear necessary. A plant gate price of only $0.35/gal would be necessary to compete with natural gas or residual oil in 1992, which means that a price subsidy (on top of loan guarantees) of $0.30/gal or more would be necessary to make methanol viable in this market. An operating subsidy of approximately $1.50 million per year would thus be necessary for a 5000-ton/year plant, or approximately $3 billion over its 20-year lifetime. It is doubtful this level of support would occur when the technology demonstration and production experience can be gained by selling into higher value markets with much lower costs to SFC.

As far as the State of California is concerned, there is little to be gained from subsidizing production of methanol because the Federal Government has already assumed that role. It is in California's interest, however, to have a western coal-to-methanol project among those awarded assistance by SFC. The state can improve the likelihood of this type of project by helping prospective project sponsors and supplying data on California markets for methanol. There does not appear to be a justification, however, for any state-sponsored production subsidy to either augment or duplicate SFC's program.

The one area where the State, through its Public Utility Commissions, can make a contribution to lowering the cost of methanol production is in further development and the eventual demonstration of the once-through methanol, coal-gasification, combined-cycle concept. Potential efficiency gains in the once-through process imply that a cost saving of about 20% (aside from utility financing impacts) may be possible from such a system, compared to a dedicated methanol plant.[50] Proposed experimental programs by California utilities for development of this process should be given careful consideration by PUC.

E. NEAR-TERM PROGRAMS

One area where the State of California might be able to improve the acceptance of methanol as a fuel is in removing institutional barriers arising from regulations and restrictions not conceived with methanol in mind. The California Energy Commission (CEC) has been active in searching for such

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[50] Economic Evaluation of the Coproduction of Methanol and Electricity with Texaco Gasification - Combined-Cycle Systems, Electrical Research Institute, EPRI-AP 2212, pp. 7-15 - 7-16, January 1982.

unintended barriers and has been successful in eliminating the most important obstacles. For example, the state gasoline tax will be levied on methanol on a Btu basis equivalent to gasoline rather than on a gallon basis. Taxing methanol on a gallon basis would have penalized methanol relative to gasoline. The state has also sponsored tax credits for converting vehicles to neat methanol use, which have been responsible for initiating fleet conversions within California. In general, CEC has been very diligent in encouraging alcohol fuel use through barrier elimination, developing test information through its alcohol fleet test program, and providing incentives for vehicle conversion. The intent of this section is to examine what further steps are warranted in view of the findings of this study concerning the comparative viability of methanol as a fuel in the near to mid term.

The focal point of the State's plan currently is the $5 million program to purchase and support approximately 1000 fleet vehicles, to establish 50-100 commercial refueling stations in California, and to test methanol-fueled CHP pursuit vehicles. These activities are intended to help develop market-pull, which will eventually lead to a self-sustaining methanol fuel market. Related efforts are also underway to demonstrate methanol in heavy-duty diesel engines and in stationary applications (repowering and co-firing). These other programs for different types of applications are important to CEC's strategy of developing methanol uses that displace the majority of refined products from crude oil. The Commissions's rationale for this strategy is that an alternative fuel which only displaces gasoline, for example, could have adverse effects on the existing petroleum product slate, necessitating refinery modifications and/or relative price changes in refined products. The stated goal of these programs is to accelerate the "take-off" point for self-sustained commercial market growth.[51]

Given the abrupt reduction in the expectation for conventional fuel prices that has occurred in the past 2 years, and the significant rise in projected cost of synfuels, it is important to assess what government programs can realistically accomplish in this environment. First, it is clear that the viability of synthetic fuel projects has deteriorated significantly in this 2-year period, as evidenced by the cancellation or postponement of numerous synfuel projects. Second, the excess capacity in OPEC oil production makes a near-term oil disruption less likely than it was a few years ago. The net effect of these factors is that the market viability of the long-term neat methanol-fueled vehicle market supplied by western coal has been pushed back until after the year 2000 in the most likely scenarios. The major fuel producers have little incentive, in the view of this study, to move aggressively toward creating the supply and distribution network needed for the use of neat methanol as a large-scale transportation fuel in the foreseeable future. There are, however, other selected markets where methanol will be used successfully during this period: octane enhancement, some captive fleets, and limited use by utilities. Programs that are oriented

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[51] Smith, et al., Alcohol Fuels for California: Establishing the Market, Synthetic Fuels Office, California Energy Resources Conservation and Development Commission, 1982.

toward these type of goals can be successful in the period before 1990, but not if they are expected to lead to a private passenger car market.

The California 1000-vehicle fleet program can be very effective in demonstrating the use of neat methanol-fueled vehicles in captive fleets. With over-the-road competitiveness, it is estimated that an annual sales volume of 4000 to 10,000 vehicles per year is potentially achievable within California. In order for California's program to be successful in stimulating both other California purchases and fleet activity in other states,[52] credible information must be generated and disseminated to potential users. In reviewing of the description of the program, there did not appear to be sufficient resources devoted to collecting that information and diffusing it to potential fleet users. It is recommended, therefore, that resources be included to provide these functions so the program can stimulate better producer and consumer decisions in the longer term. Ideally, the way to implement such a process would be to go to the fleet purchasers/operators and determine the type and quality of data they need to make well informed decisions on neat methanol-fueled fleet vehicles, and then structure the data-collection effort to answer these questions. Given this study's analysis of the fleet market, the following types of data would appear to be important to these potential areas:

(1) Long-term maintenance record (engine wear).

(2) In-use fuel economy record by duty cycle.

(3) Long-term emissions performance.

(4) Driveability performance by area within the state and season of the year.

(5) Resale experience.[53]

As this information is assembled, there needs to be a careful plan for dissemination to potential fleet users both in California and the rest of the nation. A start to developing this data was begun with the Alcohol Fleet Test Program,[54] in which much useful information was assembled and will be published as the testing of each fleet is completed. As useful as this data will be, however, it will be based on a limited number of methanol-fueled vehicles (19 and 40 neat methanol-fueled vehicles in Fleets II and II, respectively), which does not permit the needed segmentation of end-use

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[52]The benefit to California of stimulating sales in other states is the potential reduction in vehicle production costs through increasing volume and greater manufacturer competition.

[53]For an experimental program the State may want to take responsibility for the resale program directly to avoid problems that may arise with a developmental technology.

[54]See Chapter 8 of the Technical Report for a description.

experiments or a large measure of data reliability. Thus, this study urges the addition of a long-term testing program structured to the 1000-vehicle fleet purchase.

In stationary applications, the potential market with the greatest promise for being economically viable is overfiring with a small percentage (10-15%) of methanol. As discussed in Chapter 9 of the Technical Report, this concept, if successful, can lead to a justifiable premium for methanol sufficient to overcome its added cost if the capacity factors of plants constrained by NO_x emission restrictions are expanded. In effect, the value of this added operational capacity added to the value of methanol fuel can be substantial, but it is limited to those plants that are NO_x-constrained. This study strongly supports the conducting of tests to confirm the potential performance of methanol in the overfiring mode. To be of greatest value, however, it is important for overfiring with methanol to be tested against overfiring with natural gas. A significant proportion of the benefits of overfiring may be achievable at lower cost with natural gas overfiring, which would reduce the justifiable premium for methanol. This submarket of utility operations is relatively small (1750 ton/day of methanol)[55] compared to utility fuel, but quite significant relative to current use of methanol as a fuel. Thus, although a major use of methanol is not anticipated as a fuel substitute for residual oil or natural gas in utilities, it may be benefically used in highly selective applications (e.g., overfiring in environmentally restricted plants).

One possible method for achieving greater use of methanol within California is for government policy to be used to promote (perhaps even require) utility applications as a means to provide a base for expanding fuel use into transportation markets. For a number of reasons, it is felt that this policy would not be a desirable means to transition to large-scale use of methanol as a transportation fuel. First, the value of methanol in transportation markets (particularly octane enhancement) is considerably higher (i.e., at least double) its value as a utility fuel.[56] As a result, methanol will be used first in these higher value markets and only be applied to lower value uses as methanol competition increases production and lowers price. Second, the cost of producing methanol in large quantities will be too high to compete with conventional utility fuels (with the exceptions in the footnote below). Thus, utility customers would have to pay a large premium ($\$3/10^6$ Btu for methanol from remote natural gas) over current utility fuels, which cannot be justified by any realistic assessment of the benefits. Third, the experience gained in transporting, handling, purchasing, storing, and using methanol would be based on utility use, which would not carry over to transportation fuel companies. Fourth, although the quantities of fuels used by utilities are sufficiently large to utilize the output of a coal-to-methanol plant (once thought to lower

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[55] 10% methanol overfiring at Ormond Beach, Scattergood, and Long Beach powerplants (see pages 9-49 to 9-52 of the Technical Report).

[56] Excluding specialty uses such as overfiring and perhaps remote peaking units. The reference here is to the value of octane enhancement per gallon compared to residual oil or natural gas.

cost through volume production), the cost of methanol would be considerably higher than from much smaller plants based on remote natural gas. Thus, the strategy of inducing utilities to use methanol through public policy as a means to transition to more widespread use in other applications is not very attractive. This conclusion is not intended to imply that public support of programs to test methanol use in potentially viable utility applications is inappropriate, but rather that they should be justified based on their own merits as to their ability to benefit utilities and their customers.[57]

F. SUMMARY OF THE ROLE FOR STATE POLICY

The first step in determining the appropriate policies for the public sector in the evolution of methanol as a fuel in California is to examine to what degree the private market is not providing proper incentives for methanol. Rationales for justifying a public role were examined for an oil import premium and an environmental premium on fuel emissions. Although quantitative estimates on these types of premiums are admittedly imprecise, they do provide some rough guidelines on whether the social benefits of methanol are sufficient to justify its cost.

With regard to oil import premiums, a recent analysis[58] places the range of the premium for the country at $8 to $18 per barrel, with a medium value of $10 per barrel. As discussed in Section VII.A, however, the justifiable premium for a unilateral California policy would be considerably smaller because the state uses only approximately 5% of the U.S. oil. Based on this data, the range for a justifiable unilateral California oil import premium would be very small: from $0.50 to $1.00 per barrel. In terms of methanol, this would correspond to from $0.09 to $0.17 per million Btu, which is insignificant given the uncertainties of this crude estimate.

In the environmental area, premiums for methanol may be justified by the avoidance of alternative costs of reducing emissions of SO_x and NO_x associated with using conventional fuels. The premiums for environmental value were estimated in Chapter 9 of the Technical Report to have a range from zero to $\$0.20/10^6$ Btu for added NO_x reduction and from $0.15 to $\$0.65/10^6$ Btu for SO_x reduction. Thus, summarizing the premium value for methanol use in a representative stationary application would yield the range of values in Table 7-4.[59]

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[57]Including environmental benefits that were discussed in Section VII.B of this Summary Report.

[58]Energy Modeling Forum, World Oil, Stanford University, Stanford, Calif. EMF Report 6, February 1982.

[59]The potential premium for methanol use in overfiring is not considered because the application would appear to be potentially viable in only very limited applications.

Table 7-4. POTENTIAL PREMIUM VALUE FOR METHANOL IN STATIONARY APPLICATIONS (1981 \$/10^6 Btu)

PREMIUM SOURCE	VALUE RANGE
Oil Import Premium	\$0.09 - \$0.17
NO_x Reduction	0.00 - 0.20
SO_x Reduction	0.15 0.65
TOTAL	\$0.24 \$1.02

The more likely values of the premium are in the lower end of the range for the rest of the 1980s because (1) the likelihood of a major disruption is low in the near term owing to the excess capacity in OPEC, (2) there is an accepted NO_x reduction plan being implemented that makes the incremental value of further reductions zero, and (3) natural gas availability has improved considerably, which greatly reduces the cost of SO_x reduction. Thus, the state can impose policies that effectively correct for these externalities by raising the value of methanol by \$0.25/10^6 Btu or even double that amount to allow for reasonable estimation errors. The key point, however, is that the cost of methanol relative to conventional fuels is so much greater than this justifiable premium that it would have virtually no impact on methanol use. For example, if policies were enacted within California to internalize the premium values shown in Table 7-4, the value of methanol versus residual fuel oil would be approximately \$6.87 to \$7.65/10^6 Btu, whereas its value relative to natural gas would be \$6.49 to \$6.69/10^6 Btu. The delivered cost of methanol from remote natural gas or coal would be approximately \$9.25 and \$16.00/10^6 Btu, respectively. Thus, the impact of these types of premiums would be ineffective in influencing actual purchase decisions. Obviously, policies could be devised to force methanol use in spite of these major additional costs, but there is no justifiable basis for policies of this nature. Thus, in the case of stationary applications, the impact of government policies to internalize oil security and environmental premiums would not affect the private-sector decision process.

The premium value of methanol as a transportation fuel is even more difficult to assess than stationary application fuel because the incremental abatement costs are not well documented. Obviously, the import premium component would apply to transportation fuels that are compared with methanol. In the environmental arena, there would be no SO_x reduction value for methanol because gasoline does not yield this type of emission, but there presumably would be a value for reductions in NO_x, reactive hydrocarbons, and particulates. As part of this study, an evaluation was made of the potential impact of neat methanol-fueled vehicles upon long-term (year-2000 and beyond) ozone formation. The results[60] indicated that methanol-fueled

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[60]Reported in detail in Chapter 6 of the Technical Report and summarized in Section VI of the Summary Report.

vehicles can have a beneficial impact in reducing ozone after the year 2000, given that in the interim the emission inventory changes as described in Section VI. By the year 2000, however, the potential improvement is minimal from neat methanol-fueled vehicles because the number of vehicles that could be in the automobile fleet is quite small and the contribution of automobiles to the emission inventory will have been reduced substantially from current levels by current and ongoing technology improvements. The combination of these two factors limits the impact of neat methanol on peak ozone formation to approximately a 2.5%-potential reduction in the year 2000. This impact is probably too small to be significant given the uncertainties in the projected inventories and modeling process. The results do indicate that in the much longer term (beyond 2000) the potential impact could grow to be an important part of an overall air-quality strategy. An appropriate role for public policy in stimulating use of alternative transportation fuels would be to internalize differences in air-quality implications from alternative fuels. Although it would require an effort that extends well beyond the scope of this study, it is urged that a policy be thoroughly examined to institute differential state registration fees and transportation fuel taxes based on environmental implications of the alternative fuels. The type of policy that needs investigation is not a subsidy program for alternative fuels, but rather differential taxes that reflect the differential impacts on air quality of alternative fuels.

For any pollution abatement program to be efficient (least costly) for a given target air-quality goal, the marginal costs of abatement should be roughly equal among all emission sources. Thus, one goal of such a program would be to achieve a balance in incentives at the margin to abate NO_x, reactive hydrocarbons, and particulates between stationary and mobile sources. The air-quality impact of a vehicle depends on the vehicle technology, the fuel used, and the amount it is driven; thus, a differential tax program would probably have to utilize both registration fee differentials and fuel tax differentials to properly reflect these differences. Both producers and buyers of vehicles would have incentives to modify their behavior. Producers would have incentives to have their vehicles in lower registration fee classes (because that would improve their saleability) and would invest in cost-effective measures to lower emissions. Abatement measures that are too high relative to the tax (incorporated in the registration fee) would not be pursued because they would add more to the vehicle cost than the savings in registration fees. Consumers would take into account both the registration fee and the fuel price (incorporating differential taxes) differential in making their vehicle selection. Those users who drive relatively more annual miles would presumably be more influenced by the differential fuel taxes than those who drive less frequently and so make their vehicle purchases accordingly. The theory behind this type of program is not new. What is needed, therefore, is a practical assessment of whether the data and analysis techniques exist to evaluate the implications of such a program sufficiently to justify its implementation. Practical decisions would need to be made on which fuel categories would be differentially taxed (e.g., leaded gasoline, unleaded gasoline, methanol, ethanol, diesel, etc.). Similar decisions would be needed on vehicle emissions and on how many vehicle categories would have to be identified. Also, (1) the level of differential fees and taxes would have to be examined in relation to marginal abatement costs in stationary applications, (2) policy alternatives where either seasonality or regionality

would need to be examined, and (3) administrative costs would have to be examined as a function of implementation alternatives and their distributional effects assessed. It is quite possible that the type of scheme described above is simply unworkable if the administrative costs were greater than the abatement cost savings or if the air-quality consequences of alternative policies cannot be estimated, but it is worth very serious consideration.

In the absence of a policy to provide carefully justified incentives for alternative fuel adoption, there may be attempts by proponents to impose more extreme measures. For example, requirements or mandates for use of specific proportions of alcohol vehicles in California would be one example of an extreme measure that does not lead to efficient pollution abatement or oil security solutions. Thus, if new fuels are to be properly encouraged in a very uncertain future environment, it makes sense to do so in a flexible way that will be applicable under a wide range of circumstances.

G. DEALING WITH "THE CHICKEN OR THE EGG" PROBLEM

One often-discussed obstacle to implementing widespread use of methanol in transportation is that the retail distribution system must expand rapidly in anticipation of automobile manufacturers producing and selling neat methanol-fueled vehicles to the general public. Obviously, it would be very expensive and risky for fuel producers/distributors to create the neat methanol distribution system when volume is extremely low based solely on anticipation that sales will expand. Given that ower-the-road competitiveness is not anticipated for neat methanol-fueled passenger cars until the early 1990s, there does exist a mechanism that could reduce this distribution cost and risk considerably by using the normal replacement cycle of pumps and storage tanks in the distribution system.

The problem with distributing methanol is that part of the existing gasoline distribution system (seals, hoses, patches in tanks, etc.) would not be compatible with methanol use. Compounding the problem is the fact that the most recent cycle of replacements at retail outlets has been done with fiberglass tanks instead of steel, which makes the existing system even less compatible with methanol. Creating a parallel system for methanol by replacing functional equipment for gasoline presents a major cost and hence an obstacle to methanol. The lead time that exists, however, before methanol can compete as a private passenger car fuel provides time to create a threshold distribution system much more efficiently. Currently in California, there are approximately 18,000 retail gas stations supplying transportation fuels to the public. As a general rule, the tanks and pipes in these stations have an expected life of 20 years, which, with a uniform replacement rate,[61] would imply about 900 replacements per year. A policy that California may consider is starting a tax incentive in 1986 which could be created to subsidize the added cost of methanol-compatible tanks and pipes (over the replacement cost which would be incurred anyway) in a small percentage of the replaced

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[61] Actually, the replacement rate is not uniform because stations were installed in waves, which leads to heavy replacement periods.

equipment. For example, if 20% of the regularly scheduled replacements (tanks, pipes, pumps) were made methanol-compatible each year, that would imply approximately 150-180 conversions per year. Thus, if this program were started in 1986, by 1992 about 1000 systems would be in place that could be used to distribute methanol. Some cleaning of the system would have to be done when the conversion actually took place, but that would not impose a major problem. The cost of methanol-compatible systems versus what would be installed without this policy is a crucial factor in its usefulness. As discussed in Chapter 8 of the Technical Report, the cost for replacing a tank, piping, and two pumps at a typical service station is approximately $50,000 in 1981 dollars for a fiberglass system and slightly less for a steel system. The latter, although less expensive, has a lifetime which can be considerably smaller, depending on the climatic conditions to which it is exposed. In addition to the costs of more frequent replacements with a steel system, there are additional costs arising from station disruption and the risk of damage caused by undetected leaks. With the relatively dry climate in much of California, the added cost for methanol-compatible systems should not be great or a major impediment to methanol use. It is recommended, therefore, that the state examine the tradeoffs in implementing such a program in the 1986-88 period. The benefits from this type of policy would be that the state would have in-place a means to diversify rapidly in the case that neat methanol becomes suddenly more viable in the early 1990s (resulting from rapid oil price escalation, technological improvements in neat methanol-fueled vehicles, or less costly production techniques). The costs of such a program would appear to be fairly modest. If the needed subsidy were $5000 per installation, then 150 stations per year would cost $750,000 in lost tax revenues to the state. Some form of repayment might be even negotiated from the distributors to the state at the time of actual conversion to cover some of this cost. Although this is not a trivial sum of money, the cost over 6 years is $4.5 million to create a threshold distribution system of 900 retail outlets. If instituted in this type of incremental fashion using the normal replacement cycle, the retail distribution barrier need not be a massive obstacle to widespread methanol use.

H. DERIVED LIKELY ROLES FOR METHANOL

In the previous sections, the rationale for a government role in influencing the methanol market has been discussed from the perspective of the State of California. The intent of this section is to summarize whether the implementation of those policies to credit methanol for its potential value in pollution abatement or in reducing the impact of an oil disruption would significantly accelerate the use of methanol within the State. As shown in Section F, the total of the unpriced benefits which appear justified are probably in the range of $0.25 to $1.00/10^6 Btu for methanol. The estimate for the oil import premium within the state is extremely crude, but it would require a major effort to refine the value further. Based on the best information available now, therefore, the premium would be quite small because the security component has been estimated nationally at approximately $2.00/bbl, which would have to be reduced for California alone. As an example, if this $1.00/10^6 Btu premium (see Table 7-4) were added to the value of methanol in stationary uses, for security improvement, NO_x abatement and SO_x abatement the impact on the viability of methanol in these markets would be inconse-

quential. The problem is simply that the lower bound on delivered methanol costs in the latter part of the 1980s (in 1981\$) is approximately \$0.60/gal or approximately $\$9.25/10^6$ Btu. With the price of utility fuels currently under $\$5/10^6$ Btu and most forecasts placing them at \$6 to $\$7/10^6$ Btu by 1990 (in 1981\$), there is little rationale for concluding that government policy, which is justified in terms of net benefits, would affect the market at all through the mid 1990s. A combination of unlikely events could, however, lead to some viable markets in the stationary applications market by the early 1990s. If the high-price fuel scenario were to occur, natural gas were unavailable to electric utilities and methanol were obtainable at prices near $\$9/10^6$ Btu, then some use of methanol in these applications would be viable. At this point in time, however, this combination of events appears unlikely and thus, although further testing and experimentaton appears warranted, implementation of methanol use in the stationary application sector is not. Obviously, it is possible to subsidize methanol so that its cost is less than its value to users and get greater implementatoin within the state, but presumably the goal is to only consider policies which benefit Californians.

In the transporation markets, the potential value of methanol premiums are much more difficult to estimate as noted earlier. For California acting alone, the security value would be quite small reflecting the fact that a single state, even one the size of California, cannot insulate itself from an oil disruption if the rest of the country has not also reduced its vunerability. Thus, for California acting alone, the justifiable premium would have to be lower than the national premium for oil import security estimated at approximately \$2/bbl.[62] Even if this full premium were attributed to methanol in transportation uses, the impact would be very small. For example, \$2/bbl oil import premium would be equivalent to less than \$0.03/gal of methanol used in neat methanol vehicles. Once again, given the cost of methanol relative to gasoline or diesel fuel, this premium would not impact the methanol market in any significant way. As a means to summarize these effects visually, Figure 7-2 shows the impact of adding justifiable methanol premiums to the market value of methanol shown earlier in Figure 5-1 for 1992.

As indicated in Figure 7-2, the implementation of State policy to add premiums for oil import security and pollution abatement does little to the methanol market scenario for 1992. In transportation markets the octane enhancement market and light-duty vehicle market are potentially slightly improved over the "business as usual" case. The stationary applications market would still remain non-viable as long as gas were available to the industrial sector. For utilities, even in the case where gas is unavailable, the addition of the premium would not change the conclusion that methanol is uncompetitive as a fuel.

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[62]Oil import premiums have been estimated as ranging from \$8 to \$18/bbl with a median of \$10/bbl, but of this total the major portion is associated with the market power component (\$8/bbl) and only \$2 for the security component.

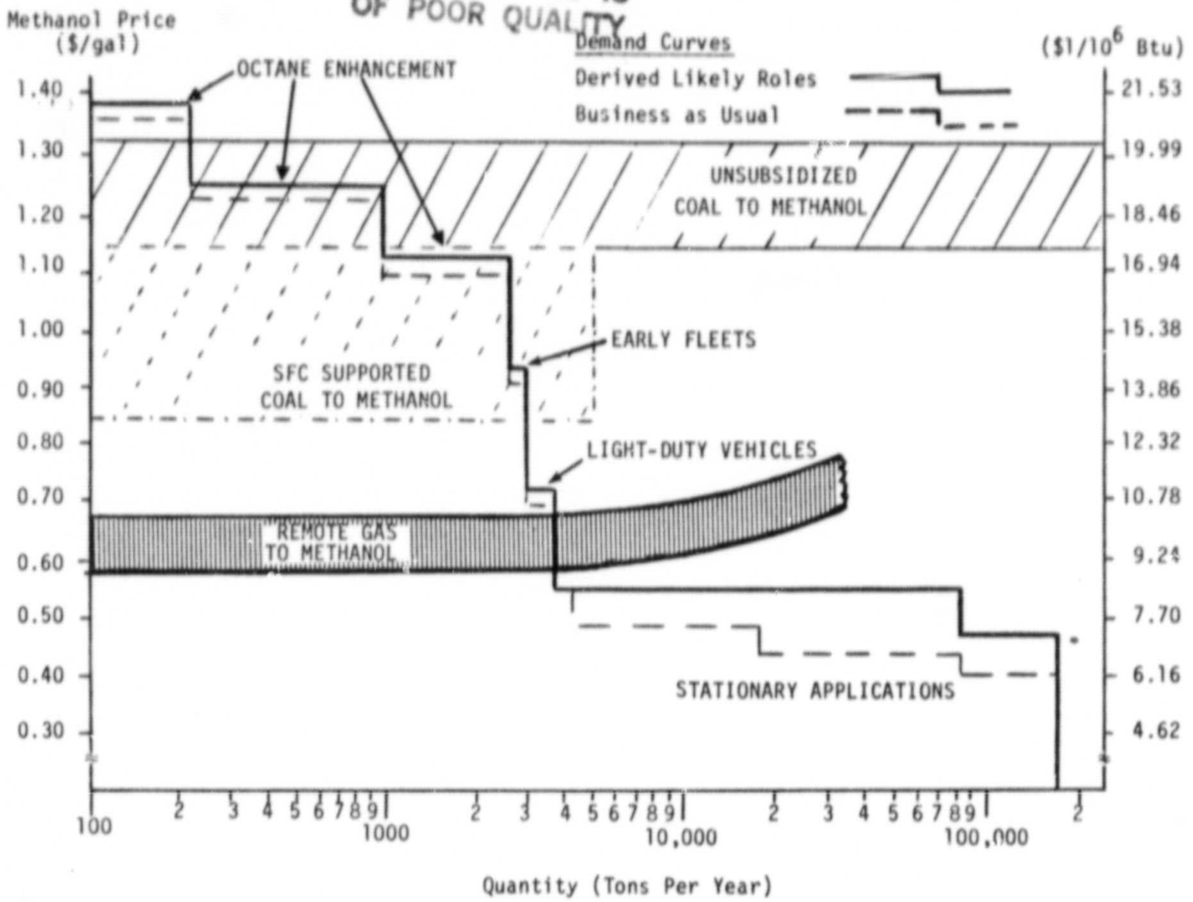

Figure 7-2. DERIVED LIKELY ROLES FOR METHANOL IN CALIFORNIA IN 1992

The conclusion is that the "derived likely roles" for methanol which result from government policies[63] are not any different from the "business as usual" case where no policies are implemented. Although premiums may be warranted, the values which appear reasonable, based on studies currently available, cannot overcome the very large extra cost of methanol over conventional fuels. Much more work can be done in this arena in terms of refining the premium value of clean domestic fuels in California. Based on the data and analysis available at the time of this study, however, there does not appear to be a case that state policies to correct market failures would significantly affect the use of methanol in California.

[63]Interpreted here to mean policies where specific benefits arise because of externalities which currently undervalue clean-burning domestic fuels. No rationale has been found for stimulating methanol for other reasons.

SECTION VIII

CONCLUSIONS

A. OVERVIEW

A successful strategy for making a transition to widespread use of methanol as a fuel must be consistent with the realities of the fuel market in which it must compete. In this study an attempt has been made to assess the available information to determine the salient features of how this market might evolve in California. The strategy that emerges from this approach is to establish the necessary preconditions for methanol to be used as a fuel in both transportation and stationary-application markets by creating mechanisms to reward externalities which are unpriced in the marketplace and by modifying undesirable institutional barriers which might slow methanol production and use.

1. Competitive Environment

It is clear that in the last year and a half, the climate for introduction of synthetic fuels has changed dramatically. In 1981, oil prices in constant dollars reached a peak from which they have since fallen nearly 15%, but even more important is the change in expectations for the future. In early 1981, many knowledgeable forecasters were predicting real price increases for oil of 3% annually for 20 years, but by the end of 1982 there was much evidence to the contrary. Although opinions still differ widely covering the spectrum of the three energy scenarios described earlier in this Summary Report, the consensus of expectations for oil prices has clearly fallen. This major change in expectations is partly a result of information that was simply unavailable 2 years ago, or so speculative that it was not credible. The response of energy users (demand elasticity) has exceeded expectations by a wide margin. Because oil is extremely price-inelastic in the short run, analysts were not well equipped to predict if or when reactions to the 1974 price increase would occur. The response took 5 to 6 years to occur and coincided with an economic show-down that has made oil prices extremely soft. It is widely believed that real oil prices will remain constant through 1985 and only rise to 1981 levels by the end of the decade. All the demand adjustments in creating a more energy-efficient capital stock, which will result from the 1979 price run-ups, have not occurred as yet. As a result of the demand adjustments to oil price run-ups, oil price deregulation, and the worldwide economic recession, OPEC is operating at only 19 million barrels per day, although existing capacity is over 30 million barrels per day. Consequently, when Iran and Iraq began attacking each other's oil facilities, there was no significant price impact, either from real supply areas or from consumer country panic buying. The supply response, on the other hand, has not been too significant as yet, but the time lags necessary to find, develop, and commence commercial activity are 8 to 10 years, which will mean that only in the mid to late eighties will the full impact of the price rises be reflected in supplies.

This change in attitude toward synfuels and the change in expectations concerning future fuel prices is clearly evident in the number of cancelled

plans in the synthetic fuel industry. When lowered oil price expectations are coupled with highly escalated shale development costs, the viability of these projects is diminished dramatically. To some degree, the massive shale cost escalation is a result of feedback effects from the 1979 oil price run-up, a very large infrastructure development, and low productivity in remote environments. Although each type of synthetic fuel would have unique characteristics with regard to these cost factors, they would all be affected to some degree. Large coal-based synthetic fuel plants to be built in relatively undeveloped western coal fields or in Alaska would certainly be impacted similarly. Obviously, methanol from coal is not immune to these factors and this is a significant reason why cost estimates made prior to the oil price run-up in 1979 are typically unrealistically low. Thus, for very good reasons, the climate for synfuels has cooled considerably in the last few years. It is in this environment that methanol must establish itself if it is to move ahead in the nearer term.

2. Methanol Supply and Demand

As has been stressed in the transition-period discussion (1987-1992, see Section V), the sources of methanol in the near term will be dominated by natural gas as the feedstock. After deregulation of pipeline gas, no new plants are likely to be built based on pipeline gas, although it is anticipated that most will continue to operate for the rest of the 1980s and early 1990s. The plants throughout the world already under construction or in planning stages using remote natural gas will be sufficient to satisfy modest fuel demands through 1987. The projected excess methanol production capacity, relative to chemical market demands in this period, could exceed one billion gallons per year. In addition, the worldwide excess capacity could be even larger if SFC should support a methanol project. Of course, relative to fuel demands, one billion gallons per year is a rather small quantity and could be utilized as an octane enhancer in a small proportion of U.S. unleaded gasoline.

Beyond this planned capacity, the incremental source of methanol becomes other remote gas projects, including barge-mounted methanol plants around the Pacific rim. There is sufficient remote gas to supply California demands for the next 15 years at prices which would undercut any unsubsidized coal-to-methanol project. Even with SFC support other than direct price subsidies, methanol from coal cannot be profitably produced and delivered to California for less than \$0.80/gallon in 1981 dollars, which is higher than methanol from Cook Inlet or Indonesia for remote gas prices up to \$2.50/10^6 Btu.

The market picture in the transition is that, at expected production prices, the stationary applications market will be small. If the overfiring concept can be demonstrated to work effectively and plants currently limited in operation by NO_x regulations can be operated at rated capacity using 10% to 30% methanol, the implied premium would be sufficient to make methanol competitive in these plants. The maximum market in this case, however, is approximately 1500 ton/day, and the overfiring technology which is yet to be fully demonstrated must prove successful. Thus, the scale of the utility market is small at best and years away from reaching that potential. There is virtually no chance that methanol can be used economically as a fuel for

repowering boilers, even with credit for eliminating the need for environmental control technology.

Only two realistic interim markets exist for methanol in the transition period: blends and neat methanol-fueled vehicle fleets. These markets, because of the high cost of transportation fuels and additives, are potentially competitive for methanol. The blends market in California has a maximum demand of 4000 ton/day of methanol, but it is limited by the availability of tertiary butyl alcohol. Normal market forces will induce industry to exploit this market in a timely fashion. The state could aid the process by facilitating methanol transport by tanker and pipeline. For neat methanol-fueled passenger vehicles, the rate of growth will be slow because neat vehicles based on remote gas will not achieve a slim over-the-road cost advantage until shortly after 1990, although this advantage will increase through time. This advantage will not be as large as it has been the last few years for diesels over gasoline vehicles. Thus, with a narrower cost advantage and a thinner distribution network, neat methanol should tend to grow more slowly than diesels. But even if it grows at the diesel rate from 1978 to 1982, the proportion of neat methanol-fueled vehicles in the California fleet by 2000 would be about 12%, which would consume about 12,000 ton/year (120 10^6/gal) of methanol. This level of demand is consistent with supplies of methanol from remote natural gas around the Pacific Rim.

Furthermore, given these penetration rates, the potential impact of neat methanol-fueled vehicles by 2000 is quite modest. If 12% of the vehicles were fueled by neat methanol, the projected impact on peak ozone in the South Coast Air Basin would be to reduce it less than 4%, which is a small part of the problem. In the longer term, the impact could be larger as the methanol fleet grows.

In the view of this study, methanol is a potentially superior synthetic fuel for California based on the data available today. It is in the same cost range (probably less expensive) than gasoline from shale, but also has end-use environmental properties that are superior to shale and other transport fuels from coal. The problem is that none of the synthetics are competitive on a large scale at this point in time, thus, building a foundation for growth is the most fruitful role for the State of California and the potential producers. A key qualifier in the above statement is "competitive on a large scale," because methanol can be competitive in selected applications which will yield the needed experience and test data to make decisions on larger markets.

The limits to large-scale methanol use are real and attempts to overly encourage the methanol market will be self-defeating. Methanol from coal is not economic and will not be viable (unsubsidized) for quite some time. The interim feedstock is remote natural gas, which will not be elastic in supply for huge fuel demands. Thus, modest growth in fleets and passenger cars can be supplied without driving up prices significantly, but rapid growth in vehicle sales or utility demand could not be supplied at a competitive price.

Although coal-to-methanol is not the least costly source of methanol, currently it is an important factor in the evolution of the methanol market. Based on the interactions with the fuel producing companies, it seems unlikely

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that any transition to neat methanol passenger cars can begin (other than centrally fueled fleets) until coal-to-methanol shows promise of being a competitive fuel with gasoline. As of this point in time, that expectation for competitiveness is simply too far in the future (beyond 2000). Thus, although there are less costly sources of limited quantities of methanol, in the nearer term the real threshold still is determined by the viability of coal-to-methanol.

3. Recommended Strategy

It has been demonstrated that the neat methanol market is not really "the chicken or the egg" problem it has often been called. It is true that automobile makers and fuel producers must simultaneously provide vehicles, fuel, and a distribution system, but the scales of these systems are not so large as to preclude a workable solution. Reasonably efficient production runs of neat methanol-fueled vehicles could be made at 30,000 vehicles per year for a given producer, production from remote natural gas shipped by tanker can be made efficiently at scales of 200 million gallons per year, and distribution requirements for a regional introduction of one station in ten are well within the fuel industry's resources. If the climate of 1980 in terms of fuel price escalation had persisted until today, an agreement between an auto manufacturer and fuel producer might quite likely already have been made. In today's environment it is a more difficult decision, but the long-run wisdom of pursuing methanol as a serious contender for a long-term transportation fuel is still sound. Clearly, the trend in California (and, in the long run, the rest of the country) is that conventional transport fuels will become more expensive and higher levels of environmental improvement will become increasingly more difficult (and more expensive) to attain. Both trends favor methanol use in the long run.

When this study was organized, it was hoped that it would be possible to help the State of California devise an implementation strategy for transitioning to large-scale methanol use. During the course of the study, it has become clear that such a goal is simply not consistent with the market realities of methanol versus conventional fuels. The next step for methanol use in California must be considerably more modest, involving further experimentation, testing, and demonstration. There are some small, but high-valued potential uses for methanol in the next 10 years which can help in keeping the cost of the needed experimentation relatively low.

The strategy that California should pursue is to exploit the small cost-effective markets in the near term (octane enhancement, fleets, capacity-limited power plants), eliminate the barriers to expensive transport and handling of methanol, and convince industry that California is the regional market for neat methanol introduction. Three key actions are needed: obtain credible test data from the California fleet program, establish criteria for port facilities for unloading and storing methanol, and continue the State's aggressive policy on eliminating regulatory uncertainties (gasoline taxes, RPV limits, emission requirements). The automobile manufacturers can accelerate the market significantly if the advanced automotive technology (e.g., methanol dissociation) can be perfected and incorporated in neat methanol-fueled vehicles by the mid 1990s. This technical advance would reduce the required

fuel factor from 1.7 to 1.8 in 1992 to about 1.6, which would significantly improve the over-the-road cost-effectiveness of neat methanol-fueled vehicles and probably lower their emissions as well. On the producer side, there are potential technology improvements that can lower long-run production costs. Some of the most interesting concepts involve co-producing methanol and electricity from coal; further development is needed. Most of our oil producers view themselves as energy companies, which is the broad perspective needed to adjust to long-term changes in markets and conditions. Within the next decade, it seems likely that one such company will make this necessary commitment for what will be a long-term transition.

B. DETAILED CONCLUSIONS

1. Resources

(1) Substantial quantities of western coals are potentially available for methanol conversion for use in California. In particular, the subbituminous coals of Black Mesa, San Juan, Yampa, and Powder River appear to be promising long-run sources with combined potential resources of about 1600 billion tons, with 500 billion tons having less than 2000 feet of overburden.

(2) There are significant (relative to likely demands) remote natural gas resources in the Pacific Rim that could be used to support methanol fuel demands through 1995. Based just on current rates of reinjection and flaring, the remote gas in the Pacific Rim could support over 8 billion gallons per year of methanol production -- ignoring Alaska's North Slope. Although it is not anticipated that anywhere near this amount will actually be used for methanol production, the point is that gas resources are not the binding constraint on methanol production in the next 15 years.

(3) Indigenous California resources are either too limited in supply (bioenergy, petroleum coke) or too expensive (heavy oil in rock) to support a major transition to methanol fuel within the state. Small selective markets, however, will probably be served by those in-state resources.

2. Production Costs

(1) Methanol production costs from alternative resources are heavily influenced by capital cost differences which vary significantly by type of feedstock. Approximate estimates in unescalated, 1981 dollars per annual gallon of capacity are: natural gas (industrial site), \$1.00/annual gallon; natural gas (barge-mounted plant), \$1.50/annual gallon; coal, \$3.00/annual gallon; and lignite, \$3.40/annual gallon. With this approximate relationship of capital requirements, very significant cost advantages in feedstocks for coal and lignites are necessary to overcome the capital disadvantage.

(2) Although market gas in the United States and throughout much of the world will have a value comparable to oil products (residual U.S. oil), there are significant quantities of remote natural gas with opportunity costs that are considerably less than oil. As a result, methanol production in the near term is dominated by remote natural gas for California markets. It has been concluded that sufficient remote gas deposits exist on the Pacific Rim with values of $\$1.50/10^6$ Btu or less to satisfy California methanol fuel demands through 1997.

(3) Methanol production costs per 10^6 Btu from coal should be 17% to 19% less expensive than M-gas, resulting from a 10% increase in capital costs and an 8% efficiency loss in further processing. This extra production cost is compounded in an end-use efficiency loss of at least 15% in the fuel factor required for neat methanol-fueled vehicles versus gasoline, making the overall extra cost per mile traveled at least 30% and probably more. Thus, M-gas production is <u>not</u> an important GR. near-term or long-term factor in the methanol transition because M-gas cannot compete in the near-term gasoline market and is much less economic than neat methanol in the long run.

(4) Given the significant cost advantage of remote natural gas over coal and petroleum coke, these resources are not important to the near-term transition. Other resources from bioenergy may compete in specialized applications (e.g., non-grid-connected peaking units), especially considering a potential \$0.20/gal incentive in neat methanol uses and up to \$0.40/gal in 10:1 gasoline blends. Bioenergy, however, is not economic in large-scale uses, even for such applications as dual fueling a large boiler. Thus, both indigenous feedstocks and transporting feedstocks into California for processing are not crucial to a successful methanol transition.

(5) The key feedstocks for synthetic fuels for California are remote natural gas in the short run and coal or shale oil in the long run. In all these cases, processing will be done much more efficiently near the resource site. Thus, California needs to do all it can to facilitate entry points for products into the state. In the near-term, port facilities at Long Beach and San Francisco Bay, and at coastal power plants are important. In the long run, pipelines from western coal fields will be crucial links in efficient systems. It is clearly in California's interest to promote transportation competition between railroads and pipelines by supporting legislation that increase the state's energy transport options.

(6) There are a number of methanol production facilities under construction throughout the world which will come on-line in the early to mid-1980s. In spite of this added capacity, the market price of chemical methanol in the next 5 years will probably remain over \$0.70/gal, in 1981 dollars. The

deregulation of natural gas and the termination of "old" gas contracts by 1985 will leave virtually all the existing industry on market gas by 1985. The variable costs of production by such producers will be over \$0.64/gal by 1985 if natural gas is \$4.50/10^6 Btu or more. Thus, any producer who cannot earn his variable costs will shut down. Although there will be some infra-marginal producers earning larger returns (e.g., Canadian suppliers with below-market gas), the marginal U.S. producers will not sell below \$0.64/gal, keeping sales in chemical markets at this level or higher when transport and some return is added. Some foreign producers may sell to West Coast fuel markets for a minimum of \$0.53/gal. At prices lower than this, they can absorb the transport cost and import duty and compete for the chemical market at the Gulf. As a result, expectations of very inexpensive methanol (i.e., below \$0.53/gal) resulting from excess capacity are unwarranted.

(7) The moderation in the expectation of natural gas prices for 1985, given lower oil price forecasts, has made the existing production capacity viable in the mid term. Using market gas at \$4.50/10^6 Btu to \$4.75/10^6 Btu in 1985 to 1987 (in 1981\$), existing producers will be able to compete in chemical markets with marginal production costs of \$0.67/gal to \$0.70/gal at the plant gate. Although remote gas from foreign sites will be less expensive at the plant gate, the combination of an 18% duty and transport costs of \$0.10/gal from Pacific Rim producers will keep most foreign competition out of the market. The U.S. industry will rely on its sunk capital to compete, as new plants would not be viable based on market gas.

(8) One of the implications of the Synthetic Fuel Corporation's potential support for coal-to-methanol plants may be to displace part of the existing U.S. chemical methanol production industry. Study estimates indicate that a coal-to-methanol plant, in Alaska's Cook Inlet for example, with SFC support could deliver methanol to California for about \$0.81/gal by 1987, in 1981 dollars. The additional cost of transport from California to the chemical markets located primarily in the Gulf Coast would add enough by either train or tanker to bring the delivered cost to around \$0.90/gal. An estimate of the variable costs alone of producing methanol from market gas in existing plants is \$0.67/gal, ignoring capital amortization. This margin is probably sufficient for these producers to continue to make debt repayment and interest charges on non-fully-amortized plants compared to the Alaskan coal case. However, other coal-to-methanol projects nearer to chemical markets and those with other incentives (relating to biomass feedstocks) may be able to undersell existing producers sufficiently to force them to sell at below full-cost recovery. Thus, SFC should carefully examine applications for coal-to-methanol projects for this potential

impact on U.S. industry. The intent of the synthetic fuels program is to make the United States less dependent on foreign oil, not to subsidize some U.S. producers into driving other U.S. producers out of business.

(9) If remote natural gas is the preferred feedstock for methanol in California, a concern is whether the resource would be used for LNG conversion instead of methanol. There is no doubt that strictly as an energy carrier in large gas deposits (i.e., over 300 million SCFD), LNG is less expensive to produce and ship under 5000 miles. At longer distances, the cost of transportation in cryogenic tankers becomes more of a factor. Some have suggested that even at distances 5000 to 10,000 miles, the added shipping cost of LNG does not offset its significant production advantage. The key point that is often missed in these comparisons is that 10^6 Btu of methanol and LNG are not of equal value in either stationary or transportation applications. In transportation, on a Btu basis, methanol will be more valuable than gasoline. Thus, when value is considered, methanol will successfully compete for use of some remote natural gas with LNG, especially in smaller gas fields. In other words, methanol producers will be able to offer some remote gas owners a small premium over potential LNG producers in some locations and still have a viable product in many circumstances.

3. Methanol Transport

(1) Where large volumes or distances are required, there is a clear economic advantage to transporting methanol by means of tankers or pipelines compared to rail or truck. In 1981 dollars, the average cost to transport crude oil relative to tanker cost (1.0 by definition) was pipeline 1.8, barge 3.0, rail 10.8, and truck 18.4. For new transport options (e.g., building new pipelines or tankers), the relative costs would change somewhat, but the basic pattern of tanker and pipeline superiority for long distances at high volumes would be sustained. Thus, in the long term, a widespread methanol fuel industry would rely on tankers for overseas methanol shipments from remote natural gas and pipeline transport of methanol from western coal sites.

(2) In the near-term and transition periods, the likely quantities of methanol demanded could not justify a methanol pipeline from western coal fields. Such projects would have to utilize either rail transport of coal for conversion to methanol near the end-use center or rail transport of methanol from a minemouth plant. Early plants based on remote natural gas, however, could bring methanol directly to California end-use centers, thus creating a significant advantage for remote natural gas feedstocks over coal in the near term. Truck transport would only be used for local distribution to fueling stations for fleets or private passenger cars.

4. Transportation

(1) There will exist a small market for methanol as a gasoline blending agent by the smaller (topping and hydro-skimming) refineries. This market appears to be presently existent at current methanol prices but mainly unsatified. However, the fraction of gasoline produced in California by such refineries is quite small (approximately 4%). For some of these refineries, octane number-of-barrel costs may be sufficiently high to justify the use of high-price co-solvents such as propanols if low-price tertiary butyl alcohol is not readily available. For the most part, however, it will be the availability of relatively low-price tertiary butyl alcohol on the West Coast that will determine the magnitude of use of methanol as a blending agent in California. If all of the TBA produced in the United States were shipped to the California markets, approximately 70% of the gasoline produced in California could be blended with methanol. The most likely application of methanol TBA in California would be in the blending of higher octane unleaded gasolines by the larger refineries or by blenders or small refineries to upgrade regular grade to premium grade. Unless the front-end volatility of the gasoline into which it is blended is reduced, Reid Vapor Pressure limits may be exceeded and/or driveability may suffer. Because the small gasoline blender has little control over the front-end volatility of the gasoline he receives, this reduces the potential market. For the larger refineries, there is the potential to "back out" butane and reduce volatility; however, it may not be an economic solution to providing octane if the refinery's existing octane number-of-barrel cost is low. Compared to the production of a remote natural gas-based methanol plant of approximately 3000 ton/day, the potential demand from the blending in the refinery sector in California is rather small. For example, if it is assumed that 20% is a reasonable estimate for the amount of gasoline that could potentially be blended with methanol, the daily methanol demand is approximately 900 tons of methanol, or a little less than than one-third of a single plant's capacity.

(2) There now exists a very small methanol market in commercial fleet vehicles supported by several small companies performing vehicle conversions to neat methanol. Even if quality methanol-fueled vehicles were available and the price of methanol fuel was such that these vehicles would have an over-the-road cost competitiveness with gasoline, the near-term potential market is probably still limited to between 4000 and 10,000 vehicle sales per year. This is due to constraining factors such as uncertainty on resale value, ready availability of methanol fuel, and customary maximum trip lengths for the vehicles. If methanol vehicles were, in fact, sold at this volume, it would imply an increase in methanol demand of about 20 to 75 ton/day. Such a volume is

quite small in comparison to a remote natural gas methanol plant size of between 2000-4000 ton/day.

(3) There exist several methanol medium- and heavy-duty engines that are close to being commercially available. Several of these engines have been road-tested, both in New Zealand and Germany. The UPS Texaco TCCS engine was originally designed to run on conventional fuels, but has been demonstrated to function satisfactorily on methanol. Based upon the road test work to date, there does not appear to be a significant efficiency advantage of methanol vehicles over diesel vehicles in medium- and heavy-duty applications. This implies that no significant market would be expected to develop until methanol and diesel reach approximate parity in the price per Btu. Under the baseline petroleum price scenario, Btu parity with distillate oils is not reached by low-price remote natural gas-based methanol until well after the year 2000.

(4) An important factor in neat methanol viability as a transportation fuel is the efficiency gain expected compared to a moving conventional baseline vehicle. The analysis shows that there will be gains in neat methanol-fueled vehicles from higher compression ratios, leaner fuel mixture and heat of vaporization that are potentially 1.7 in 1982 and slowly attenuate over time as the baseline improves. If dissociated methanol technology is assumed, the fuel factor is from 1.53 to 1.63. It appears, however, that with likely improvements in conventional gasoline vehicles, projected fuel factors as low as 1.3 for neat methanol-fueled vehicles are unrealistic in the long term.

(5) Using the baseline petroleum price scenario, liquid methanol-fueled vehicles become competitive with gasoline-fueled vehicles in the early 1990s if the methanol is assumed to be derived from remote natural gas. The competitive advantage in over-the-road costs after the early 1990s is not dramatic. This implies a relative modest growth rate in the methanol-fueled vehicle market. Dissociated methanol technology would move the breakeven date forward by several years, but more importantly, it would significantly increase the cost advantage of methanol relative to gasoline. Under this baseline petroleum price scenario, coal-based methanol would not be competitive with gasoline in the foreseeable future, even with dissociated methanol vehicle technology. With a high-price oil scenario, the feedback of higher oil prices to methanol production from either remote natural gas or coal would be only significant enough to modestly improve the viability of neat methanol from remote natural gas and leave coal-to-methanol uneconomic. In the lower price scenario, on the other hand, neat methanol is uneconomic over the forecast period.

5. Environmental Analysis

(1) The total quantity of organic emissions from methanol-fueled vehicles could be reduced below what is considered the practical limit for gasoline-fueled vehicles because methanol and formaldehyde, the major components of exhaust from methanol-fueled engines, are much more easily oxidized by catalysts than are the high-molecular-weight hydrocarbons of gasoline. The emerging technology, based on the catalytic dissociation of methanol using exhaust heat from the engine, would further reduce organic emissions from methanol-fueled vehicles.

(2) Methanol has a relatively low flame temperature and thus produces inherently lower emissions of NO_x than most other fuels. Emissions of NO_x from methanol-fueled engines are about 50% lower than emissions from engines fueled with petroleum-based fuels. Thus, methanol has the potential to produce lower NO_x emissions from both mobile and stationary sources.

(3) The emission of NO_x from methanol-fueled vehicles illustrates the complex relationship between emission levels and fuel efficiency. For example, when the emissions of NO_x for the methanol-fueled 1981 Ford Escorts used in the Los Angeles County fleet test were reduced from 1.0 g/mile to 0.25 g/mile, fuel consumption increased by 26%. Thus, in the near term, when the primary supply of neat methanol-fueled vehicles is through conversion of gasoline-fueled vehicles, care must be taken in interpreting fuel efficiency data and in setting environmental requirements to consider both emissions and efficiency. In the long run, optimized neat methanol-fueled vehicles are not expected to have to sacrifice efficiency for lower emission levels.

(4) Methanol could form part of an effective strategy for the control of photochemical smog in Los Angeles. Under optimistic patterns of neat methanol-fueled vehicle adoption developed in Chapter 8 of the Technical Report, the impact of methanol on peak ozone concentration in the South Coast Air Basin by the year 2000 is projected to be a reduction of 2.5% to 4.0%. This modest impact is determined by the methanol contribution to the automobile stock, which will be limited to 10% to 15% of the total by 2000, given a rate of penetration consistent with diesels since 1977. In the much longer run (i.e., 2000), methanol could contribute more substantially to abatement of ozone concentration given a longer period for neat methanol-fueled vehicles to affect the composition of the automobile fleet. Thus, in the nearer term (i.e., 1992), there would be no measurable impact on air quality from methanol use in vehicles, and in the longer term (i.e., 2000), it would be a marginal contribution (i.e., 2.5% to 4%) to peak ozone reduction. It is only in the much longer term (i.e.,

2020 and beyond) that methanol could make a significant contribution to Los Angeles basin air quality improvement. Thus, it is unrealistic to rely on methanol use as a significant instrument in meeting air-quality goals for timeframes up to and including the year 2000.

6. Utilities

(1) The most significant potential market for methanol (up to 80,000-ton/day) is composed of existing utility steam turbine and combined-cycle units that currently fire oil and gas. The actual extent of this market will, of course, depend strongly on future cost and availability of oil and gas. A switch to methanol would be most cost-effective for combined-cycle units (about 6000-ton/day) that may otherwise have to rely on expensive distillate oil.

(2) Southern California Edison is the most likely large-scale utility user of methanol in California because of a large inventory of modern oil- and gas-fired units, strong environmental pressures, and some concern over access to natural gas.

(3) Existing industrial boilers and heaters (80,000-ton/day) and future industrial cogeneration systems (10,000-ton/day) also represent potential markets of substantial size for methanol, but they currently use natural gas in most cases and have higher priority than the utilities for obtaining gas.

(4) In order for methanol to be competitive in utility markets, its price per unit of energy will have to be competitive with the prices of residual oil for utility boilers, distillate oil for combined-cycle and industrial units, natural gas (if available), and other synfuels. Some adjustments for such factors as modification costs and environmental benefits will be appropriate in this comparison, but they will probably have a second-order effect in the absence of legislative action or a major change in PUC policy.

(5) Comparing projected methanol prices with demand curves based on oil and gas price scenarios developed in the study, it is seen that in the baseline scenario methanol will not be competitive with conventional boiler and turbine fuels in the next 20 years (with the possible exception of distillate oil applications under the most extreme scenarios for emission reduction requirements). In the high-price oil scenario, the feedback effects on methanol production costs are sufficiently strong to keep methanol from being viable in stationary applications.

(6) If methanol were to become cost-competitive sooner than expected, a phased development period would be expected before

the full market potential could be realized. This period would last from 4 to 8 years, depending on the urgency of the circumstances that led to methanol becoming competitive. (The buildup of the methanol supply would probably take longer than this.)

(7) Within the utility market, methanol is not competitive with distillate, residual oil, or natural gas under the baseline oil price scenario. In the high-price oil scenario, methanol still does not become competitive in utility markets because of feedback effects to methanol production costs. It does get close by 1997 to being competitive in combined-cycle units with a fuel demand of 6000 ton/day, but only in the case where natural gas is unavailable.

(8) For industrial markets, methanol is not competitive in the baseline scenario with either oil or gas. In the case, however, of the high-price oil scenario, methanol would reach virtual price parity with a small market of approximately 1000 ton/day of methanol demand. The larger markets remain uncompetitive for methanol if natural gas is available. Thus, the key issue is whether gas is available to industrial customers. It seems highly likely that gas will be available to industry, especially in the high-price oil case, where general business activity declines.

7. Policy

(1) The rationale for the public sector attempting to influence the likely market outcomes for methanol has been examined and in general the evidence to date does not justify intervention in the market process. The difference between the "business as usual" case and the "derived likely roles" resulting from government policy are not significantly different.

(2) Methanol production costs are sufficiently high that even granting methanol a premium for its environmental benefits would not be sufficient to overcome its cost differential versus conventional fuels.

(3) Import security premiums should be instituted at the national level rather than by the State of California. Any premium which could be justified solely by benefits within California would not overcome methanol's cost disadvantage.

(4) The next step for California policy to encourage methanol use is best directed toward further research, experimentation, or demonstration. There do not appear to be any sensible policies to induce widespread utilization in the private passenger car market or stationary applications market in the near term.